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Functional Requirements and Concepts of Frequency Converter's Oil Application Control Program

Master of Science Thesis

Examiner: Professor Teuvo Suntio
Examiner and topic approved by the Council of the Faculty of Computing and Electrical Engineering on 6th May 2015

ABSTRACT

TAMPERE UNIVERSITY OF TECHNOLOGY
Master's Degree Programme in Electrical Engineering
TERÄVÄINEN, JOEL: Functional Requirements and Concepts of Frequency Converter's Oil Application Control Program
Master of Science Thesis, 64 pages, 5 Appendix pages
May 2015
Major: Switched-Mode Converter Design
Examiner: Professor Teuvo Suntio
Keywords: Variable frequency converter, application control program, requirements, artificial oil lifting, progressing cavity pump, electric submersible pump

The majority of exploited oil reservoirs in the world need some form of artificial lifting to transfer crude oil to the surface. Progressing cavity pumps and electric submersible pumps are two methods commonly used to do this. These pumps are able to pump from relatively small to very large amounts, thus being suitable for many different applications. This thesis studies control functionality requirements occurred among customers operating with these pumps in oil fields. Requirements are examined and designing concepts discussed. The aim is to determine how the existing application control program used with ABB's ACS880 industrial variable frequency converter could be improved so that it meets the customer requirements and responds to the market situation effectively.

In this thesis, functionality requirements were inquired from ABB sales and marketing persons who collect information directly from customers. In addition to that, the main competitors of ABB in the field of artificial oil lifting were analysed. Order of priorities and guidelines for requested functionalities were then formed based on the collected information. The most requested topics were related to functionalities reducing the amount of sensors needed in the system. This means that the program should be able to make estimations based mainly on motor behaviour. Production monitoring possibilities and better sand cleaning functions were also widely requested. In addition to these, the monitoring of a motor's acceleration in order to detect a stuck pump was seen as an important enhancement, as was detecting gas pockets down in the well.

To add new requested functionalities to the control program, pump and reservoir conditions need to be modelled better. In some cases, a lot of practical testing is also required, but monitoring improvements, for example, can be done with small modifications to the current program. Designing at least the most requested functionalities would give a good competitive edge over the main competitors.

TIIVISTELMÄ

TAMPEREEN TEKNILLINEN YLIOPISTO
Sähkötekniikan koulutusohjelma
TERÄVÄINEN, JOEL: Toiminnalliset Vaatimukset ja Toteutustavat Taajuusmuuttajan Öljysovellusohjelmalle
Diplomityö, 64 sivua, 5 liitesivua
Toukokuu 2015
Pääaine: Teholähde-elektroniikka
Tarkastajat: Professori Teuvo Suntio
Avainsanat: Taajuusmuuttaja, sovellusohjelma, öljynpumppaus, epäkeskoruuvipumppu, uppopumppu

Valtaosassa maailman öljylähteistä käytetään jonkinlaisia pumppuja tuotantomäärien parantamiseksi. Epäkeskoruuvi- ja uppopumppu ovat kaksi yleisesti käytettyä pumppua öljysovellusten yhteydessä. Kyseiset pumput soveltuvat hyvin monenlaisiin sovelluksiin, vaihdellen pienistä hyvinkin isoihin tuotantomääriin. Tämä diplomityö tutkii näiden pumpputyyppien yhteydessä ilmenneitä vaatimuksia ja kehitysehdotuksia öljysovellusten ohjaustoiminnallisuuksien osalta. Tavoitteena on määrittää miten ABB:n ACS880 taajuusmuuttajalla käytettävää sovellusohjelmaa tulisi kehittää, niin että se vastaisi asiakkaiden kysyntää ja olisi kilpailukykyinen markkinoilla.

Sovellusohjelman vaatimuksia ja kehitysehdotuksia kysyttiin pääasiassa ABB:n myyntivastaavilta, jotka keräävät tietoa suoraan öljyteollisuudessa toimivilta asiakkailta. Kyselyn lisäksi työssä käytiin läpi pääkilpailijoiden ratkaisut. Näiden perusteella muodostettiin prioriteettijärjestys ja suuntaviivat kehitettäville toiminnallisuuksille. Kysytyimmät parannukset liittyivät toiminnallisuuksiin, jotka vähentävät tarvittavien sensorien määrää pumppausjärjestelmässä. Tämä tarkoittaa, että ohjelman olisi kyettävä tekemään arvioita olosuhteista, pääasiassa moottorin toiminnan perusteella. Parempia tuotannon monitoirointimahdollisuuksia ja hiekanpoisto-ominaisuuksia kysyttiin myös laajasti. Näiden lisäksi tukkeutuvan pumpun havaitseminen käynnistyksen yhteydessä sekä kaasutaskujen automaattinen havaitseminen nähtiin tärkeinä kehityskohteina.

Pumppujen ja öljylähteen olosuhteita täytyy mallintaa tarkemmin, jotta uusia toiminnallisuuksia voidaan lisätä nykyiseen sovellusohjelmaan. Osa parannuksista voidaan toteuttaa olemassa olevia ominaisuuksia hyödyntämällä, mutta joissain tapauksissa vaaditaan paljon testaamista. Jo pelkästään muutaman eniten vaaditun toiminnallisuuden kehittäminen antaisi monessa tapauksessa hyvän edun kilpailijoiden suhteen.

PREFACE

This thesis was written for ABB Oy Drives, Low Power AC Drives unit and Tampere University of Technology. I would like to thank my supervisor and superior Ari Huttunen for giving me the opportunity to write this thesis and providing valuable counseling through the process. I also want to thank other ABB co-workers who contributed to the progress of the thesis, especially R&D application software team and product and sales managers in various countries.

Thanks also go to my examiner Professor Teuvo Suntio. At this point I also want to thank all other TUT professors, lecturers and assistants who taught me through the university.

Special thanks go to Hervannan Seminaaripäivät - fellowship, who provided valuable comments and gave boost to finish this process. At last I want to thank my whole family for supporting me during my studies.

Helsinki, 29th April 2015

Joel Teräväinen

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SYMBOLS AND ABBREVIATIONS

SYMBOLS

A_{rod}	Rod cross-sectional area [m^2]
A_p	Effective rotor area [m^2]
BP	Motor power [kW]
D	Rotor diameter [m]
d	Tubing diameter [m]
e	Eccentricity [m]
F_t	Tubing friction loss [N]
GOR	Gas/liquid ratio [l/m^3]
γ_f	Fluid specific gravity [N/A]
H_L	Net well lift [m/Pa] or [ft/psi]
H_wh	Wellhead pressure head [m/Pa] or [ft/psi]
I_{line}	Line current [A]
L	Fluid level in well [m]
M	Material coefficient [ppm/°C]
μ	Dynamic viscosity [Pa s]
N	Rod rotation speed [rpm]
n_{motor}	Motor efficiency [%]
n_{pt}	Power transmission equipment efficiency [%]
P_{ch}	Casing head pressure [Pa]
P_{cg}	Gas column pressure inside casing [Pa]
P_{cl}	Liquid column pressure inside casing [Pa]
P_d	Discharge pressure [Pa]
P_i	Intake pressure [Pa]
PI	Productivity Index [N/A]
P_{lift}	Net lift [Pa]
P_{loss}	Flow losses inside tubing [Pa]
P_r	Reservoir pressure [Pa]
P_R	Rotor pitch lenght [m]
P_S	Stator pitch lenght [m]
P_{surf}	Tubing pressure at surface [Pa]
P_{th}	Tubing head pressure [Pa]
P_{tl}	Liquid column pressure inside tubing [Pa]

P_{wf}	Flowing downhole pressure [Pa]
Q	Production amount [l] or [bbl]
R	Rod lenght [m]
Re	Reynolds number [N/A]
ρ_g	Gas density [kg/m^3]
ρ_l	Liquid density [kg/m^3]
S	Pressure loss in tubing [Pa/m]
s	Tubing lenght (also intake depth) [m]
$s*$	Perforation average depth [m]
SG_{comp}	Fluid composite specific gravity [N/A]
SG_{mix}	Composite specific gravity of water and oil [N/A]
S_s	Shear stress [Pa]
TDH	Total dynamic head [m/Pa] or [ft/psi]
T	Rod torque [Nm]
$T_{friction}$	Friction torque [Nm]
$T_{hydraulic}$	Hydraulic torque [Nm]
T_{PR}	Polished rod torque [Nm]
T_{total}	Total motor torque [Nm]
U	Supply voltage [V]
V	Displacement factor [m^3/day/rpm]
v	Flow rate [l/s] or [bpd]
W_R	Rod weight in air [kg]

ABBREVIATIONS

ACN	Acrylonitrite
API	American Petroleum Institute
bpd	Barrels per day
DHPCP	Downhole Progressing Cavity Pump
DTC	Direct Torque Control
ECS	Electronic Speed Control
ESP	Electic Submersible Pump
FKM	Fluoroelastomer
FOC	Field Oriented Control
HNBR	Hydrogenated Nitrile
IPR	Inflow Performance Relationship
I/O	Input/Output
NBR	Nitrile
PCP	Progressing Cavity Pump
PWM	Pulse Width Modulation
rpm	Rounds per minute
SAGD	Steam Assisted Gravity Draining
SPAR	Single Point Anchor Reservoir
TLP	Tension Leg Platform
VFC	Variable Frequency Converter
VFD	Variable Frequency Drive
VSD	Variable Speed Drive

1. INTRODUCTION

This Master's thesis is a customer-oriented study of how to improve functionalities of ABB's oil pumping application program used with ACS880 industrial frequency converter. In this case, unnecessary improvements, which are not asked for by customers, will not be further considered. However, the product needs to be competitive on the market, so competitors are analysed and improvements considered against them as well. The thesis focuses on providing a good overview of the pump systems with which the application control program is used, finding out the control functional requirements and discussing possible implementation principles. The final development process is left outside the thesis since it would require more time and work than is possible to include in the scope of this thesis. Nonetheless, the thesis gives comprehensive guidelines for further development.

A Variable frequency converter is in the core of the thesis. One way to control an oil pump system is to use a variable frequency converter. It processes signals coming from different parts of the system and then modifies the speed of the pump's motor so that pump's operation is efficient and safe. To improve the effectiveness of the oil pumping system, the converter could use a dedicated application control program. Compared to the standard control software that the converter uses, the application program is a bit modified software that includes added application specific functionalities. In ABB's application program designed for oil pumping with progressing cavity pumps (PCP) and electric submersible pumps (ESP), these functionalities are, for example, fluid level and backspin control. Application programs are fully software-based and usually do not require any additional hardware components.

The principles of the pumping methods mentioned earlier are quite different. A progressing cavity pump is a positive displacement rotary pump. Lifting is based on rotation and constantly variable cavities along the pump body. Shapes of stator and surface driven rotor are designed so that closed cavities are formed and rotational force moves fluid upwards from cavity to cavity. Electric submersible pumps are centrifugal pumps and have a different approach for lifting fluid to the surface. ESP pressurises fluid at the bottom of the well using rotating impellers. Due to pressure difference, fluid moves upwards. Electric submersible pumps are typically used in offshore applications and deep wells, whereas progressing cavity pumps are found more often from onshore installations.

The thesis begins with an overview of the whole oil and gas production process in Chapter 2. Generally the production process is divided into upstream and downstream sectors. The upstream sector includes the reservoir exploration, drilling, well completion and artificial lifting processes, and thus it is the sector at which the developed product in this thesis is aimed. The downstream sector includes transport and refining processes, and a quick introduction to them is also presented in the thesis.

Chapter 3 presents more detailed theoretical sections on progressing cavity and submersible pumps. The chapter discusses operation principles and different components in each system. These sections provide the basis of the technical implementation of the new application specific functionalities. This chapter also includes a more detailed section of a variable frequency converter since it is a platform of an application program. The purpose of the theoretical chapter is to provide information for the subsequent chapters, but also for general use of ABB's purposes.

The research part of the thesis is covered in Chapter 4. It presents what solutions the main competitors of ABB have for controlling oil pumps. Focus is, as in the earlier chapter, on PCP and ESP systems. The competitor analysis mainly focuses on the functionalities of different control solutions. This chapter also includes the survey that was sent to ABB's sales representatives who maintain connections to oil and gas customers on a daily basis. They were asked what kind of functionalities are requested and which functionalities they think should be made priorities when developing new ones.

Chapter 5 discusses the implementation principles of the requested functionalities. As mentioned earlier, the aim is to give guidelines rather than to design actual code for the program. Nonetheless, the chapter gives a good picture of possible ways to design these functionalities. Different issues that need to be considered during the development are also reviewed.

Chapter 6 concludes the thesis. It offers suggestions for how to proceed with different improvements. The market position of the control program with different improvements is also compared to competitors' offerings. The results of development actions can be evaluated easier with the positioning charts. This chapter answers the main question of the thesis: what kind of enhancements does the current product require to maintain competitiveness at the market.

2. OIL PRODUCTION OVERVIEW

This chapter concentrates on oil production on a general level, giving an overview of the different sections of the whole process. The base of the oil industry is a hydrocarbon mixture called crude oil (later also referred to as "oil") found from diverse reservoirs around the world. It is the raw material of commonly used petroleum products like gasoline. The worldwide average of crude oil production in 2013 was about 90 million barrels (bbl = 159 liters) per day, with USA, Russia and Saudi Arabia being the biggest producers [2]. The chemical properties of crude oil vary depending on the conditions of the reservoir. For example, heat, pressure and surrounding materials affect these properties. Some common reservoir types are presented later in this chapter. When dealing with crude oil, natural gas is a big part of the production process. Crude oil in the reservoir is usually mixed with natural gas, which is a valuable by-product and sometimes primary product [15]. Compounds such as dissolved minerals, water, sand and other gases are also found among the crude oil, which complicates the production process.

2.1 Reservoirs

Oil reservoirs are formed in anaerobic conditions where organic matter decomposes over millions of years. Eventually, oil drains through permeable layers, for example, sandstone, until it gets trapped in an impermeable pool [5]. The impermeable layer is denser than oil, preventing the oil from migrating through it. The same happens with gas, only it is formed slower than oil [4]. Because gas is lighter than oil, it accumulates on the top of oil in a reservoir while water stays under the oil layer. Erosion and tectonic movements of the ground gradually shape the reservoir and might move parts of it to a different direction. This creates oil and gas pockets to various levels in the same reservoir. A reservoir with this kind of structure is called a faulted reservoir. Figure 2.1 presents some common formation types.

A dome structure at bottom right corner appears commonly in the Middle-East [4]. A substance - usually salt - lying below the oil moves upwards through the denser rock. Flowing salt divides the oil layer in parts and eventually stops when

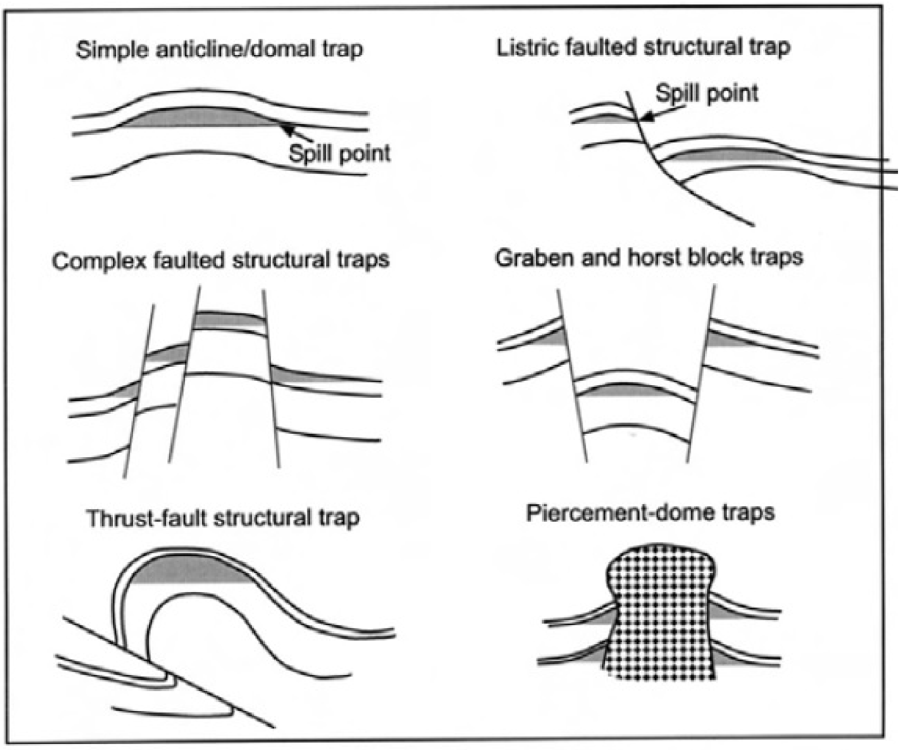


Figure 2.1: *Common reservoir formations. [5]*

encountering a more porous layer than itself. Generally, oil reservoirs are located in diverse locations over the globe ranging from more easily accessible, naturally flowing onshore wells to reservoirs several kilometres deep in the middle of ocean. The demand and price growth of oil, together with a depletion of sources at conventional locations, force exploration in more and more challenging environments and the harvesting of unconventional oil deposits [23].

The composition of oil is commonly measured with API (American Petroleum Institute) gravity. The lower the API gravity is, the denser the oil is. The most valuable oil is around 40-45 degrees API [4]. Oil in this range is considered light, and it contains the largest number of useful molecules needed in high octane gasoline and fuel. Heavy oil in the lower parts of the scale has a larger carbon number (more carbon atoms in a molecule), and thus it requires more processing in order to get the same benefits as from lighter oil. Generally API gravities in harvested reservoirs vary from 20 to 45, corresponding densities of 970 to 750 kg/m^3 [4]. The API gravity value gives a good indicative estimate of the properties of oil, but the chemical composition of different oils might be totally different even if the API gravities are the same. For this reason, other chemical analysis are needed to determine the precise usability of a certain oil.

2.2 Drilling

The equipment used in drilling depends on the location and size of the oil reservoir. Since oil reservoirs are found in various types at onshore and offshore locations, drilling solutions also vary widely. They range from micro-sized surface drills to giant offshore drilling rigs [1]. The most challenging environments are subsea wells, where already the starting point for drilling might be kilometres deep in the ocean. After the oil reservoir is mapped, a drill rig is placed on top of the reservoir. A hole is drilled with it, and then it is moved out of the way of the actual oil production platform. However, some production facilities, such as big offshore oil rigs, might be equipped with their own drilling units.

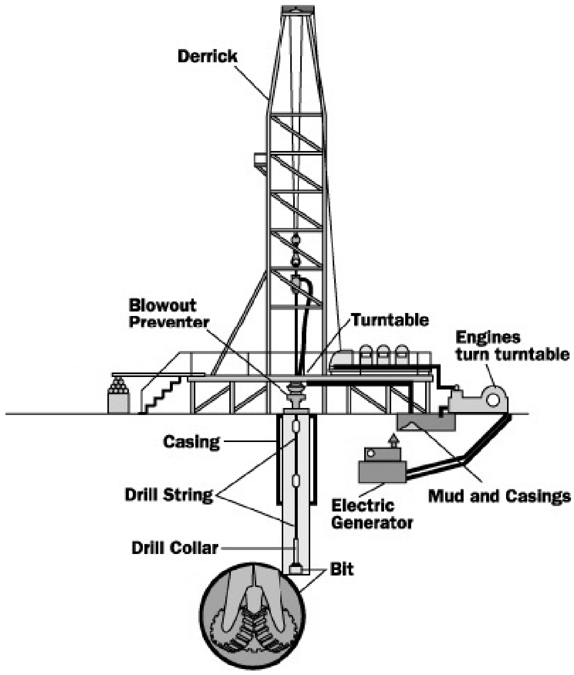


Figure 2.2: *A typical structure of a drilling unit.*

A typical drilling unit consists of a rig floor where a drilling derrick or tower stands. Power generation equipment, usually an electric motor or a combustion engine, for operating the drill is placed on the top of the derrick. A drill string is attached to the motor on the top of the derrick. The string consists of separate pipe segments, which can be added as the drill bit at the end of the string goes deeper. A typical drilling rig used in onshore is shown in Figure 2.2.

The drill bits are either roller-cone or fixed-cutter shaped, as shown in Figure 2.3. Roller-cone bits tend to be selected for conventional conditions. Tungsten carbide roller-cone bits are used with hard rock formations, whereas steel bits can be used if the drilled formation is relative soft. Fixed-cutter bits are constructed of very

Figure 2.3: *Roller-cone and fixed-cutter drill bits. [1]*

strong materials, for example, poly-crystalline diamond. They contain only one moving part in contrary to various simultaneously moving cones of the roller-cone design. Fixed cutter bits are more expensive, but on the other hand, the durability and usability are better compared to roller-cone bits. Therefore both designs appear as widely at drilling sites. [1]

One significant component in the drilling process is a mud system [14]. The mud system circulates fluid (usually called mud) from surface to the drill bit while having several purposes. Mud goes down to the wellbore inside the drill string and through the holes of the drill bit cooling these parts At the drill interface mud acts as a lubricant. The hydraulic energy of downward flowing mud is also utilized to rotate the drill. After the mud has gone through the drill bit, it is pushed back to surface, simultaneously carrying detached particles. This way the wellbore remains clean and walls of the wellbore are constantly supported. Mud in the wellbore also balances pressure conditions during drilling [16]. At the surface, mud is filtered from particles and returned to circulation. The mud system has its own mud pumps which keep the mud constantly flowing. The amount of mud circulating in the system depends on the depth of the wellbore. In offshore locations the riser between the drill rig and seafloor requires significant amounts of mud, especially if the drilling site is in deep waters. Generally, the needed amount varies from a couple hundred to several thousand barrels [1]. Usually, the mud is a water-based fluid, consisting either fresh water or sea water. Some oil-based muds are also used due to better properties, for example, higher temperature resistance, compared to water-based fluids. Oil-based muds are widely replaced with synthetic fluids due to environmental restrictions [1]. For example, drilling cuttings cannot be dumped straight back to the sea if oil-based mud is used.

Well control during drilling needs to be handled precisely, especially for safety reasons. Blowouts during drilling may cost human lives and cause major equipment expenses. A blowout is an incident where pressure discharges uncontrollable from the wellbore, scattering the drilling equipment on the way up. Blowouts form from kicks which frequently occur during drilling. A kick happens when a drill encounters a point where pressure is bigger than the hydrostatic pressure of the mud. As the pressures try to stabilize, the higher pressure occurrence "kicks" through the drilling mud. These kicks are dampened by controlling the amount of mud in the circulating system. Wells are constantly monitored, and if a severe kick is detected on the basis of warning signs, shut-down of the well is started to prevent a blowout situation. Some indications of occurring kicks are increases in mud flow, flow after shutting down the mud pumps or pump pressure decreases while strokes increase. Pressure conditions are controlled with a wellhead unit at the opening of the well. It contains valves and chokes to seal the well if necessary. The wellhead is also an important component in controlling fluid movement when a pumping process is started after drilling. [1]

2.3 Well completion

In the completion stage, the well is prepared for actual oil pumping. All the necessary equipment and components are installed and well structure strengthened with cement. After the drilling is complete, casing is placed into the wellbore. Although, some parts of it might be installed already during the drilling. The casing is a multilayer structure around the wellbore that supports the well sides and isolates the upwards flowing oil from surrounding materials. The material used in casing tubes (also called "strings") is usually steel slightly mixed with manganese [1].

The first part of the casing in the drill hole is a conductor casing. It is installed already during drilling to prevent collapses of the wall. The conductor casing covers only top parts of the wellbore. Surface casing goes a bit deeper. Its main purpose is to give blowout protection. It is fitted inside the conductor casing, as well as all casings are nested, meaning that the diameters decrease inwardly. Intermediate and production casings are the longest strings going deep down into the well. Intermediate casings reach already to the zone where pressure conditions vary widely, so sometimes multiple intermediate casings are needed to provide enough protection. A production casing is the innermost casing. It provides structure for tubing which eventually works as a transfer link to the surface. Inlets or perforations for oil and possible gas filters are assembled in connection to the production casing. [1]

Lifting equipment, such as downhole pump units, determines the more detailed characteristics of the production casing and tubing. Casing strings are usually cemented in place. Cement is pumped to the lower edge of the casing string from where it circulates upwards to the outer edge of the casing, filling the space between two different casings. [14]

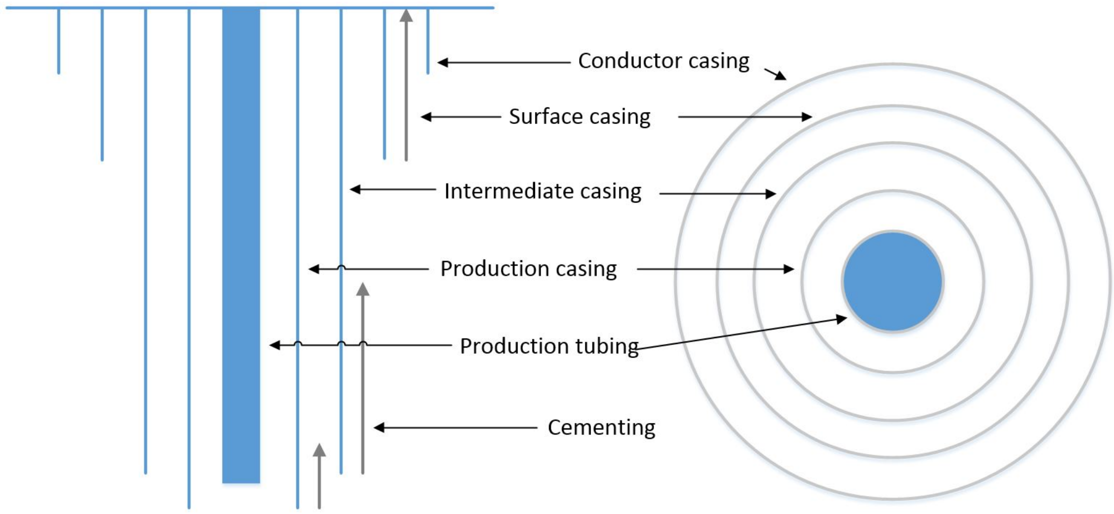


Figure 2.4: *Casing layers in completed well.*

Figure 2.4 shows basic casing layers seen from the side and the top. More casing strings might be used if the reservoir is unstable or at weak ground.

2.4 Production facilities

A production facility is the base structure for oil production. It provides resources to lift and process hydrocarbon mixtures so that they can be transferred to further treatments. The construction of the production facility depends substantially on the location of the reservoir. Onshore locations do not require so many structures around them, and different parts of the production facility might be spread wider. Offshore reservoirs require more complicated constructions, which are usually concentrated in one floating or self-standing platform. The main elements of the production facility are a lifting system and hydrocarbon processing units. In addition to these, a lot of equipment, such as piping, storages, measuring and safety devices, is needed.

2.4.1 Onshore sites

The sizes of onshore production sites vary from small, under a hundred barrels per day, installations to wide, half a million barrels per day, plants. Even small facilities are often profitable to operate since onshore wells might require only a pumping unit [3]. Transportation to further processing is easy to organize without long piping systems if production amounts are relatively low. In Figure 2.5 is a small installation where the surface equipment of the progressive cavity pump can be seen. The pumped oil is transferred to a gathering storage where oil is collected from several similar installations at the same area and collectively transferred further. Figure 2.5 also shows the other side of the size scale: a big oil sand production area. Oil sand is gathered, and the first treatment is already done at the site because transportation of raw material would cause a significant addition to expenses. Refineries which process oil to its final form, for example, gasoline, might be also at the same area.

Figure 2.5: *Onshore production facilities. Small PCP site on the left and oil sand plant on the right. [4]*

2.4.2 Offshore sites

Offshore locations require more complex constructions and engineering compared to onshore plants. That is why offshore reservoirs need to produce large amounts of oil to make them profitable. In shallow waters, production platforms can be self-contained, i.e. standing in the bottom of the sea. In some construction types, legs are hollow concrete pillars simultaneously serving as storages. When going deeper into the ocean, production facilities are floating rigs anchored to the sea floor. If there are rough sea conditions in the area, the platform has a certain shape. TLP and SPAR type rigs with floating cylinder frames are designed for such sea conditions. Figure 2.6 shows the self-contained and floating designs of offshore production facilities. Submersible units on the seabed are often used if oil wells are scattered to a wide area around the floating platform. Submersible units extract oil from different wells from which it is then led to the platform. Oil can also be brought straight to the shore if underwater piping can be implemented. Otherwise oil is transferred to the shore with tankers. [3]

Figure 2.6: *Offshore production facilities. Concrete leg gravity base (left), TLP and SPAR designs. [3]*

2.4.3 Artificial lifting

The majority of oil reservoirs are not naturally flowing, or at least the flow rate needs to be increased [17]. In these cases, some artificial lifting method is used to transfer oil to the surface. A pumping system is selected based on the size and location of the oil reservoir, especially the depth of it. A categorization of pump types can be seen in Figure 2.7 [18]. Pumps used in oil applications are either kinetic energy or positive displacement pumps [6]. Pumps are powered by prime movers like electric motors, reciprocating engines or natural gas turbines [3]. An electric motor can be controlled with a variable frequency converter (VFC). With the VFC, production can be optimized and controlled effectively. This also leads to longer life expectancy of both motor and pump equipment, since operation conditions and safety aspects are taken into account at some level. VFCs often have dedicated control programs for oil applications (discussed more thoroughly in Section 4.1).

Positive displacement pumps include some mechanical device which displaces fluid and forces fluid to move in cycles [19]. The movement of such a device can be either reciprocating or rotating. A progressing cavity pump (also called screw pump),

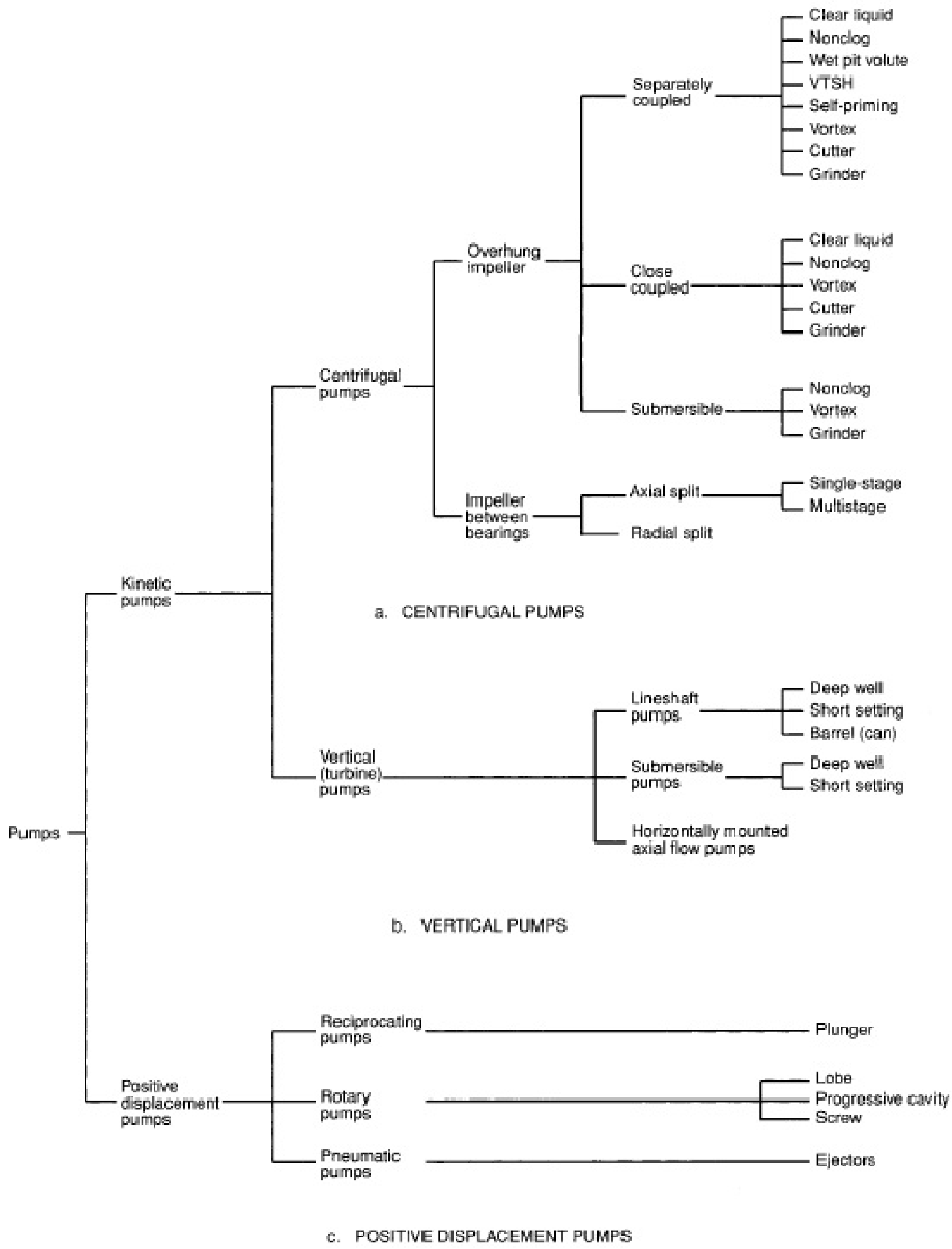


Figure 2.7: *Categorization of pump types.*

presented more specifically later in this thesis, is an example of a rotating positive displacement pump. The principle and structure of that kind of a pump is explained in Section 3.1. A PCP is common at onshore fields where it is able to pump very viscous and sandy contents from deep wells [7]. A common reciprocating type positive displacement pump is a beam pump (also called piston or rod pump). A downwards moving piston forces fluid to rise upwards in an adjacent cylinder. The size difference of cylinders causes fluid to move further upwards compared to the downward movement of the piston. Beam pumps require quite a large surface structure, so they are used only at onshore locations.

Kinetic energy pumps move fluid by increasing its pressure [10]. The pump consists of rotating impellers which increase the pressure of the fluid by increasing its velocity. In contrast to cyclic movement of fluids with positive displacement pumps, kinetic pumps operate more portable. The most common type of a kinetic pump used in oil applications is an electric submersible pump. Electric submersible pumps, also presented more precisely later in this thesis, are one type of centrifugal pumps. They are a usual choice for deep wells and also increasingly in oil sand field SAGD (steam assisted gravity draining) applications. In ESP applications, the pump motor is usually placed in downhole. This eliminates the need for long rods, which are required with progressing cavity pumps. Another, although less used, pump type is a gas lift. The principle is to inject gas to the bottom of the well, and as gas bubbles rise, they simultaneously lift fluid to the surface. [6]

2.4.4 Separation process

Rough separation of the biggest particles and sand is done at bottom of the well when oil enters the pump. At the surface, gas and other compounds are separated in a more thorough process. Usually refineries accept oil where the water content is less than one percent [3]. Oil separators are either horizontal or vertical pressurized vessels which use gravity to sort materials of different densities to individual levels [15]. Both horizontal and vertical designs offer benefits and disadvantages compared to each other. For example, solids are easier to remove from a vertical vessel, but gas bubbles vanish slower compared to a horizontal vessel.

The water and gas, separated in various stages, proceeds to their own further treatments. Gas might be processed to a marketable condition, but water needs to be clean enough so that it can be disposed. Gas separators use methods other than gravity forced separation as well, but this subsection focuses on oil treatment. A sequence chart of the separation process is presented in Figure 2.8.

Straight from the well, oil goes first into a high pressure separator. Water, oil and gas are separated in this three-phase separator. Figure 2.9 presented a simplified first stage horizontal three-phase production separator. Unprocessed oil enters the vessel through a filter called the slug catcher. It smooths turbulence caused by big

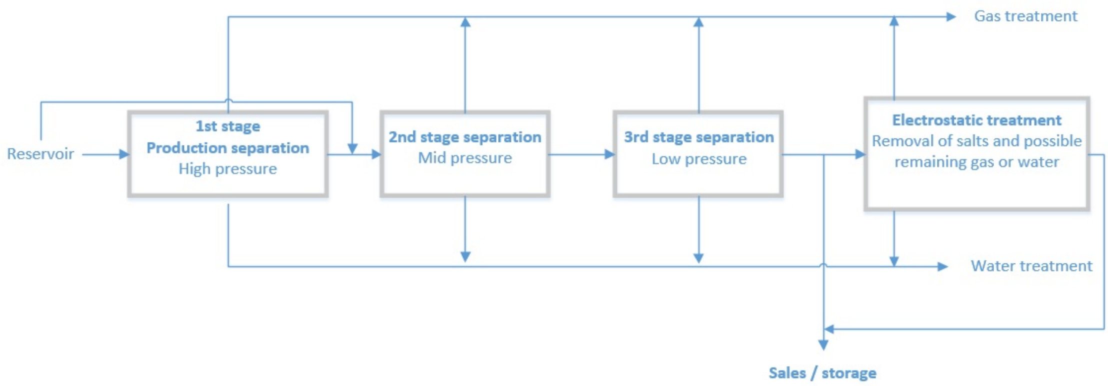


Figure 2.8: *Oil separation process.*

gas bubbles. After the separator is filled, water, oil and gas settle to individual levels. High pressure and temperature speed the process, and this stage usually takes only a couple of minutes [4]. Pressure is then reduced gradually. Gas goes to the outlet through a demister that removes remaining liquid droplets attached to the gas.

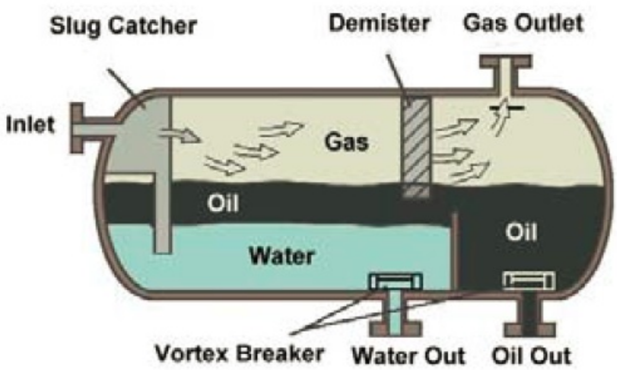


Figure 2.9: *First stage horizontal separator. [4]*

The second and third stages continue to separate substances more thoroughly. The oil outlet of the first separator leads to the second separator, which has lower pressure and temperature (still considerably higher than normal conditions). The principle is the same as in the first stage, and water cut is reduced to an allowed level or at least near to it. In the third stage separator, pressure is atmospheric which causes the remaining gas to evaporate. Heaters might be necessary with the second and third stage separators since pressure reduction after the first stage causes also the temperature to lower.

Electrostatic treatment is done after the third stage if the quality of oil needs to be further improved. The electrostatic vessel contains electrodes which form an electric field inside the chamber filled with the outcome of the third stage separator. The electric field breaks the surface bonds between different compounds. Components of the formed mixture then settle to different layers for final separation. The electrostatic separator removes still remaining water or salts like sodium and calcium. However, this kind of desalter might be placed already after the first or the second stage [4].

2.4.5 Peripherals

A production facility has a lot of equipment and devices to keep key processes in operation. Prime movers are one of the major components in production facilities. In addition to powering the main pumping unit, those are needed to power compressors. Compressors have several different purposes. Gas separation from liquid is contributed to by compressors in several stages of the separation process. Sometimes compressed gas is injected into the well to increase production. The gas lift technique naturally requires high compressed gas to be inserted to the bottom of the well. Piping system in the production field also needs to maintain certain pressure levels, which are controlled with compressors. [14]

Pipelines are an essential transfer channel for oil. Even the smallest production facilities have some kind of a piping system. Pipelines can be divided to four different categories: well flow lines, interconnecting piping, gathering pipelines and transmission pipelines. A flowline is connected to the wellhead and leads usually to a separation unit or temporary storage. In smaller sites, the flowline might be the only pipeline if further processing is done somewhere else. Interconnecting piping connects the various components of separation, measurement and heating systems inside the oil processing facility. The outcome from the processing units is then fed to a gathering pipeline that leads to a refinery or storage. If production amounts are large and oil needs to be transferred long distances, a higher capacity transmission pipeline serves that purpose. Transmission pipelines often collect oil or other petroleum products from several gathering pipelines and transmit oil collectively to refineries. Figure 2.10 shows the typical piping system in production plants. [3]

Measuring devices, referred to earlier, are necessary for two reasons. Flow meters provide information about well conditions and thus help to optimize operation. The other reason is to keep track of production amounts so that further transfer can be

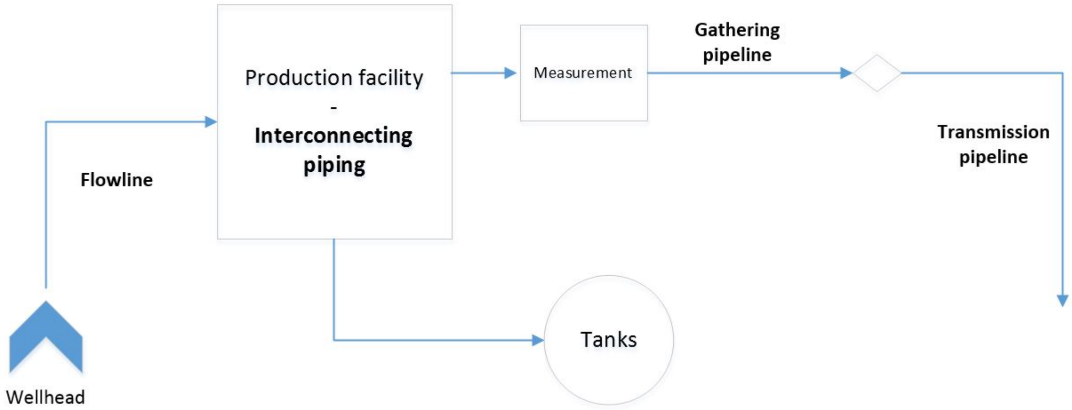


Figure 2.10: *Piping system in oil production plant. [3]*

planned and charged correctly. Usually straight after the wellhead is the first metering device, which gives feedback to the pump control system. More comprehensive measuring is done before oil is transferred further from the plant [4].

Generally three types of measuring devices are used: positive displacement meters, turbine flow meters and Coriolis flow meters. Positive displacement meters have various different designs, but the basic principle is that fluid goes inside the meter filling a certain volume. After each volume incremental is full, fluid causes motion of the measuring unit (usually spinning rotor). The volumetric flow rate can be then calculated based on this motion. Turbine flow meters operate in a quite similar way. Measured fluid or gas goes through turbine blades which rotate the rotor. Flow rate is then calculated based on the turbine cross-sectional area with the information of rotor and fluid speeds. Coriolis flow meters use the distortion of vibrating tubes to determine the mass flow rate inside the tube. The distortion caused by Coriolis force is very small, so meters need accurate sensors to detect changes in distortion, which is directly proportional to the mass flow. If the density of metered fluid is known, the volumetric flow rate can be derived from the mass flow. [3] [4]

3. TECHNOLOGY OF PROGRESSING CAVITY AND ELECTRIC SUBMERSIBLE PUMP ARTIFICIAL OIL LIFTING SYSTEMS

This chapter gives information regarding the progressing cavity pump and electric submersible pump systems. Operation principles and system components, as well as design and sizing considerations, are covered. This is essential knowledge when developing an application program that controls the whole system.

3.1 Progressing cavity pump

The progressing cavity pump is a positive displacement pump belonging in the section of rotary pumps [13]. They are sometimes called screw or eccentric screw pumps as well. The operation principle of this type of pump was developed by Rene Moineau in the early 20th century, but the pumps were not used in artificial oil lifting applications before the late 1970s. Before that, different component materials of PCP systems could not handle petroleum-based fluids well enough [6]. Since then, progressing cavity pumps have become a significant method of artificial oil lifting worldwide [20]. PCPs can pump multiphase fluids (for example oil containing gas, sand, water and other chemicals), which often makes it the only reasonable solution for challenging oilfields [13]. Progressing cavity pumps can be used in various applications with slightly different designs, but this thesis concentrates on the downhole progressing cavity pump (DHPCP) configuration, used widely in oil pumping related applications. Figure 3.1 shows the general design of the DHPCP. The downhole system consists of two main parts: the pumping unit down in the well and the drive system on the surface. The operation principle, system components and design considerations are introduced in this section.

3.1.1 Operation principle

The progressive cavity pump uses rotation and displacement of cavities to transfer fluid. A helical shape rotor rotates inside a double helical stator while indentation of

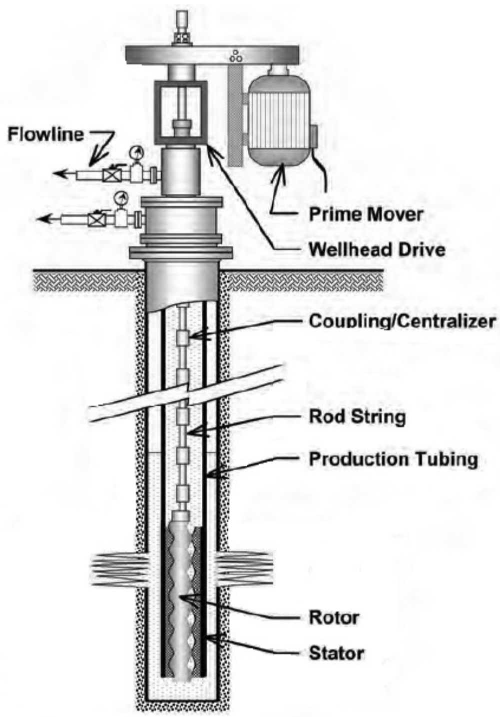


Figure 3.1: *Downhole PCP system. [6]*

the rotor and stator forms a cavity pair chain along the axis. In single lobe systems, the rate of rotor and stator threads is 1:2 (i.e. a stator have one more cavity than a rotor). The multi lobe designs (up to 9:10 rate) operate on the same principle, but single lobe systems are preferred in commercial use [9]. Single-lobe systems, compared to same size multi-lobe systems, can carry bigger particles through the pump without a rotor jamming so easily. This is possible because the volumes of individual cavities are bigger. On the other hand, multi-lobe designs offer increased flow of fluid compared to single-lobe designs [13]. The geometry of the 1:2 design is visualized in the Figure 3.2.

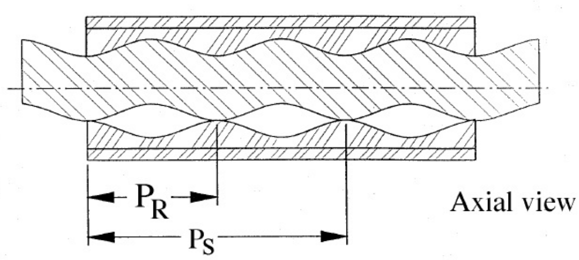


Figure 3.2: *Stator and rotor axial view in 1:2 design. [9]*

Stator pitch length P_S is double the rotor pitch lenght P_R. The same design seen from above is presented in Figure 3.3, where D is the rotor diameter and e is pump eccentricity, i.e. the distance between centrelines of the rotor and the stator.

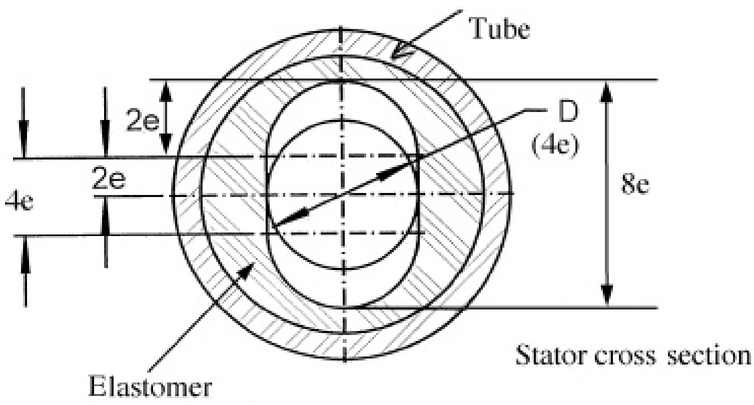
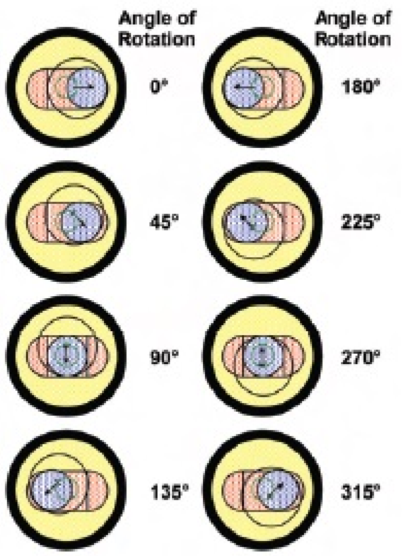


Figure 3.3: *Stator and rotor cross-sectional view. [9]*

Since the rotor and the stator are intentionally mismatching, the offset of centrelines is constantly moving while the rotor spins. Movement of the rotor in different phases of the rotation cycle is shown in Figure 3.4. The rotor's reverse rotation relation to the central axis of the stator is called nutation [13], shown as a smaller circle in the Figure 3.4. The rotor's rotation related to its own axis combined to the nutation can be seen as the rotor's back and forth movement along the stator cross sectional area.



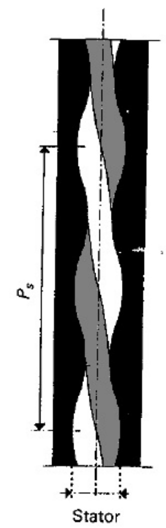


Figure 3.4: *Position cycle of the rotor. [6]* Figure 3.5: *Fluid movement in cavities. [10]*

At the beginning of each turn, the rotor is positioned in such a way that the cavities of one cavity pair are in opposing situations. One is at maximum opening and the other is closed. As the rotor turns, it displaces the fluid from the full cavity by pushing it upwards to the cavity which opens at same rate as this particular cavity closes. After a half a turn of the rotor, the originally fully open cavity is closed. Then the cavity starts to open and fill again with fluid pushed from below. When one whole turn of the rotor is gone, the cavity is at maximum opening again. Cavities of each pair are at different levels, so fluid movement from cavity to another is upwards in a spiral motion, demonstrated in Figure 3.5. Cavities that are at the same level are parallel to each other, and hence, fluid is not transferred between them. [21]

3.1.2 Rotor and stator

The rotor material is typically a high-strength stainless steel, for example ASTM 1045, plated with a thin layer of wear-resistant chrome [6]. A stator consists of stator housing and stator elastomer. Stator housing is the supportive part providing a structure for an elastomer to attach. The elastomer is a critical component of the stator since it is constantly in direct contact with the rotor and fluid. Most of the pump failures are caused by the breakdown of elastomer [6]. High temperatures, mechanical stress and corrosive chemicals require advanced properties from elastomer materials. Also the glue between the stator housing and elastomer has to withstand enough temperature and stress.

There are rough guidelines when choosing the elastomer material. However, correct composition needs to be individually tested at each well since conditions are always unique. API fluid gravity is usually the starting point for the choice of elastomer. However, even the same API gravity fluids might react differently to elastomer materials because the aromatic compositions vary between them. Elastomer should be tested at least against the volume, mass and hardness changes to see how it reacts in specific conditions [6]. The swelling of the elastomer increases the friction between the rotor and the stator, while the shrinking increases fluid leaks between the cavities. Nitrile (NBR) works as elastomer material in most of applications [20]. Properties of NBR can be modified during the manufacturing process by varying the relative amount of acrylonitrile (ACN). Higher amounts of ACN lead to better chemical resistance, but weaken the mechanical properties. NBR can stand a heat of 100°C continuously. If downhole temperatures in the well increase from that, hydrogenated nitrile (HNBR) elastomer is a better option [22]. HNBR can stand temperatures up to 150 °C. If HNBR is additionally cured with peroxide, H_2S tolerance increases, making it more durable. HNBR is more expensive than NBR, and mainly for that reason, it is not used as commonly. The third main type of elastomers is fluoroelastomers (FKMs). The development of FKMs is at a fairly early stage, but promising results have been achieved with light-oil applications [6]. Advantages, compared to nitrite-based elastomers, are significantly better heat (up to 200°C) and chemical resistance. On the other hand, mechanical properties are far weaker, which means that correct sizing of the rotor and stator is essential.

3.1.3 Production tubing

Production tubing is a channel for oil to move from reservoir to the surface. Tubing is placed inside the casing strings (casing in well completion is discussed in section 2.3), which support the reservoir structure and prevent surrounding materials, for example water, from mixing into the well. A pumping unit is placed at the bottom of the tubing so that the rotor lifts fluid straight to the tubing. The upper end of the tubing is connected to the wellhead. The rod string, which connects motor to rotor, goes inside the tubing as well. Production tubing is constantly in touch with lifted oil and gas, which is why tubing materials are more sustainable compared to casing materials [8]. Steel materials used in casing and tubing strings are categorized to characterize their strength. Table 3.1 shows the classification of steel grades, standardized by American Petroleum Institute. The usual choice for tubing material is J55 grade steel if oil does not contain significant amounts of sulphides or other chemicals [6]. The tubing can be additionally coated with boron or polyethene if the strength of the used steel grade is otherwise suitable, but corrosion wear needs to be reduced. The diameter of the tubing is generally from five to ten centimetres, but exact sizing is done according to the production estimates [4]. Tubing that is too small limits the maximum production rate and again, too big a tubing creates unnecessary costs for both tubing and casing. Rod string needs to be taken into account when sizing the tubing since rod string requires considerable volume inside it.

Table 3.1: *API steel grades used in the production tubing (and casing). [8]*

API Grade	Yield Stress, psi		Minimum Ult. Tensile, psi	Minimum Elongation, %
	Minimum	Maximum		
H–40	40,000	80,000	60,000	29.5
J–55	55,000	80,000	75,000	24.0
K–55	55,000	80,000	95,000	19.5
N–80	80,000	110,000	100,000	18.5
L–80	80,000	95,000	95,000	19.5
C–90	90,000	105,000	100,000	18.5
C–95	95,000	110,000	105,000	18.5
T–95	95,000	110,000	105,000	18.0
P–110	110,000	140,000	125,000	15.0
Q–125	125,000	150,000	135,000	18.0

Tubing anchors and catchers are sometimes used to keep tubing firmly in place. Due to high torques, tubing might start to unscrew if it is loosely tightened. High torques with low speeds occur especially if the motor is controlled with a VFC. A catcher ensures that tubing does not come off uncontrollably if an anchor fails. [20]

3.1.4 Rod string

The rod string transmits the mechanical power of the motor to the rotor. Rod string is combined from several smaller pieces coupled together. The first rod attached to the motor is called a polished rod. The polished rod goes into the stuffing box located in the wellhead. The part of the rod string that goes further than this, inside the tubing, is called a sucker rod. Rods can be manufactured from various materials, for example stainless or carbon steel [8]. PCP oil applications often have demanding torque requirements, so custom developed rods are sometimes used. Torque performance in these cases is improved by using larger diameter rods or more durable materials like monel [6]. PCP rod designs also include hollow rods. Those are necessary if diluents are injected to the bottom of well while pumping.

Couplings of the various rods are installed with as low flow resistance as possible. Pin connections are generally favoured since extra diameter for the individual coupling is small. Centralizers and rod guides are other components that increase flow losses inside the tubing. The main purpose for them is to keep the rod string in line and prevent it from scraping with the tubing [20]. Centralizers are attached either to couplings or somewhere between them. They are usually either elastomer cylinders, which reduce wear at rod and tubing contacts, or spin-thru stabilizers [6]. The rod can move inside the spin-thru centralizer, but the centralizer itself is constantly stationary in relation to tubing. Centralizers are particularly useful just above the pumping unit in the downhole. There the horizontal movement of the rod is at its highest because the rotor's offset effect to the rod has not yet stabilized.

3.1.5 Wellhead

The wellhead is one of the surface components of the pumping system. It seals the production tubing and casing openings as well as controls the incoming flow of fluids by directing them to further flow lines. This requires high pressure carrying capacity. The wellhead is needed already during the drilling phase since its pressure handling properties can be used to prevent leaks and blow-outs [4]. However, its structure slightly differs from the one used during pumping. Generally, the wellhead is constructed of several valves and chokes. With surface driven PCPs, the motor is usually attached straight to the wellhead so that the rod is easier to implement through it. The frequency converter controlling the motor can naturally be installed somewhere else in the vicinity. The part of the wellhead that gives structure for rod fastening (overall frame, rod clamps, bearings etc.) is called the wellhead drive unit, and it should not be confused with the variable frequency drive.

Casing and tubing heads are attached to hangers at the bottom of the wellhead. Depending on how many casing layers are used, one or more individual valves can be installed to access them. Casing valves are used for injecting gas into the casing. Fluid flow through the casing valves is also possible. The tubing hanger is placed above the casing hanger and valves. The tubing hanger can be sealed, and thus, blocking the well is possible with that. This way the maintenance of other surface equipment can be done safely. [4]

The structure of valves and chokes above hangers is often referred to as a Christmas tree. The master valve is the first valve straight above the hangers. Another master valve is often installed as a back-up. These valves are not used for flow control and are normally fully open during operation. Flow control is carried out with a wing (or flow wing) valve after the master valve. Straight above the master valve is a stuffing box that prevents fluid leakages in the point where the polished rod enters into the wellhead. The stuffing box is a chamber where lifted oil ends from production tubing before it is transferred forward along the flow line. In addition to these, more equipment is used if control properties require improvements. For example, a choke valve after the wing valve or a swab valve in conjunction with the stuffing box might be used. The pressure and temperature sensors are commonly placed after the master valve. Some other instrumentation, like flow meters, is also installed to the wellhead. [4]

3.1.6 Drive system

The drive system of PCPs consists of a wellhead drive unit and a prime mover, together with power transmission equipment. The main purpose of the drive system is to transmit power to the rod while controlling its behaviour in an efficient way [20]. The drive system, with the support of other equipment like feedback sensors, also ensures that pumping is done safely. This thesis focuses on surface driven PCP systems where an electric motor acts as a prime mover and is controlled with a variable frequency converter. Other concepts are, for example hydraulic systems with combustion engines and configurations where the prime mover is placed under the downhole pump. An electric motor with a VFC is more expensive compared to other concepts, but it offers good speed control features with low maintenance requirements. With hydraulic systems, there are less leak and wear problems, but they require more complex surface equipment and maintenance [6]. An electric motor driven system naturally requires electrification, which might be a significant cost in remote locations.

A common choice for the electric motor is a three-phase induction motor. The protection class of the motor frame is usually high since it is likely to be exposed to oil and corrosive chemicals. The motor is attached either straight to the wellhead or next to it. If the motor is installed straight to the wellhead, less power transmission equipment like belts and sheaves are needed. Electric motors with PCP applications are required to have good torque capabilities so that motor can be momentarily overloaded during start-up [24].

A drive system where an electric motor is controlled with a variable frequency converter is referred to as an electronic speed control (ESC) system. The basic principle is that the VFC receives feedback signals from the motor and from sensors that are attached to different pump sections. Then, on the basis of these signals, it controls the motor speed and torque, thus determining the overall pump operation. At the simplest open-loop configuration, feedback is not even necessary. In that case, frequency reference is given to the VFC, which converts it to a speed setpoint for the pump. More advanced VFCs have their own dedicated PCP algorithms which automatically control pump speed depending on the conditions. Programs react to changing events in order to get continuously optimized production. Different operation limits and configurations also help to reduce unnecessary equipment wear and thereby prolong their lifespan. ESC system solutions and the current offering of several manufacturers are presented in more detail in Section 4.1.

3.1.7 Power characteristics of PCP

In order to lift oil in an efficient way, several performance factors need to be considered when sizing the pump system. Basic principles for sizing PCP system are presented in this subsection, but it is not a comprehensive guide for doing it. The designing process is started by selecting a downhole pump which displacement factor meets the minimum requirements. The displacement factor determines what volume per day a pump can lift at a given speed. It is a pump specific value given by the manufacturer, and it depends on the geometry of the stator and rotor. Viscosity of the pumped oil affects the used pumping speed, so it needs to be examined before a downhole pump can be selected. The more viscous the oil is, the faster is the speed used. Generally the speed range varies from 100 rpm to 500 rpm [6].

After the selection of a downhole pump, torque characteristics are calculated so that the correct motor and rod can be selected. At first, a net lift requirement is determined. Net lift is the pump's differential pressure, i.e. the difference between intake (P_i) and discharge (P_d) pressures as presented in Equation 3.1.

$$P_{lift} = P_d - P_i \tag{3.1}$$

To overcome this pressure, torque equivalent to hydraulic torque ($T_{hydraulic}$) is applied to the rod [8]. It is a torque which causes fluid to move upwards (if friction losses are not taken into account). In addition to differential pressure, hydraulic torque depends also on displacement factor V as it is presented in the following eqution.

$$T_{hydraulic} = P_{lift} V Z \tag{3.2}$$

where Z is a constant (0.111 for metric system). Friction losses consist of two components: static and system frictions [15]. Static friction is caused by rotor and stator interference. System friction is a combination of other frictions caused by, for example, fluid movement. Thus, torque to overcome friction losses is added to hydraulic torque, which gives the total torque (T_{total}) to lift oil to the surface as is presented in Equation 3.3.

$$T_{total} = T_{hydraulic} + T_{friction} \tag{3.3}$$

Total torque should be calculated with the worst case method [13]. This means that the differential pressure is determined with fluid levels that cause the biggest possible differential pressure. Swelling of the elastomer and its wear over time should be also considered when calculating friction. Those are factors which cannot be determined with certainty, so designing is done with big enough margins. A friction increase caused by normal wear of a pump can be estimated with data given by manufacturer, but elastomer swelling caused by different chemicals and temperatures is more difficult to anticipate.

An electric motor is selected based on the calculated torque requirements. As mentioned earlier, friction inside the pump, combined with high overall inertia, requires higher start-up torques compared to normal operating torques. The usually required torque is between 125 and 150 % of full load [6]. An efficient way to fulfil these torque requirements is to choose a motor with a good temporary overload capacity. Motor breakdown limit should be high as well. Optimizing the motor's physical size with a higher quality motor might be more beneficial than choosing a more powerful motor.

Since a smaller motor is easier to implement in the wellhead, an oversized motor might require more power transmission equipment. Motor power requirements can be estimated with the polished rod torque T_{PR} shown in Equation 3.4 [8]:

$$T_{PR} = \frac{CI_{line}U\cos\phi \; n_{motor} \; n_{pt}}{N} \tag{3.4}$$

where C is constant (16.495×10^4 for metric system), I_{line} is line current, U is supply line to line voltage, $\cos\phi$ is power factor of the motor, n_{motor} is motor efficiency, n_{pt} is efficiency of power transmission system and N is rotational speed of the polished rod. The worst case total torque should match with the polished rod torque at a continuous operating area. A motor nameplate gives values for rated speed, but if a lower speed is used, it affects other values as well. However, a gearbox enables motor use at the rated speed while the polished rod on the other side of the gearbox rotates at the speed characteristic of the application.

After torque requirements are defined, rod durability against its stress limit is verified [20]. The rod stress limit is standard data given by manufacturers, and calculated maximum shear stress formed with individual application should not exceed it. Shear stress S_s can be calculated with the following equation:

$$S_s = \left(\left(\frac{16T}{\pi D^3}\right)^2 + \frac{1}{2}\left(\frac{(1 - 0.128\gamma_f)W_R R + A_p(0.433s \; \gamma_f + P_{surf})}{A_{rod}}\right)^2 \right)^{0.5} \tag{3.5}$$

where W_R is rod weight in air, R is rod length, s is fluid level over pump (fluid column inside tubing), γ_f is fluid specific gravity, P_{surf} is tubing pressure at surface, A_{rod} is rod cross-sectional area and A_P is effective rotor area (crest to crest minus rod area).

3.2 Electric submersible pump

The electric submersible pump is a kinetic energy pump that is part of the subsection of centrifugal pumps [26]. ESPs have been used as a form of artificial oil lifting longer compared to PCPs. As rotary pumps work on the displacement principle, centrifugal pumps use pressure to move fluid. That is why they are sometimes called pressure generators [9]. Electric submersible pumps are generally considered reliable and effective for oil applications [6]. Their production range is from 150 bpd to 150 000 bpd and can be further extended depending on the control method. ESP systems are especially popular in offshore locations and also increasingly in oil sands applications where steam assisted gathering is used [4]. Both applications have challenging installation depths and large production amounts, which often makes ESP systems the only reasonable choice. System design naturally differs from PCP systems. The biggest difference is that the prime mover is placed in the downhole, below the pump. The lack of a rod enables deeper installation depths and flexible tubing implementation. Also the amount of power transmission equipment is reduced. The placing, however, complicates maintenance, and at the moment, one of the main challenges with ESP oil applications is costs caused by downhole electric motor failures [6].

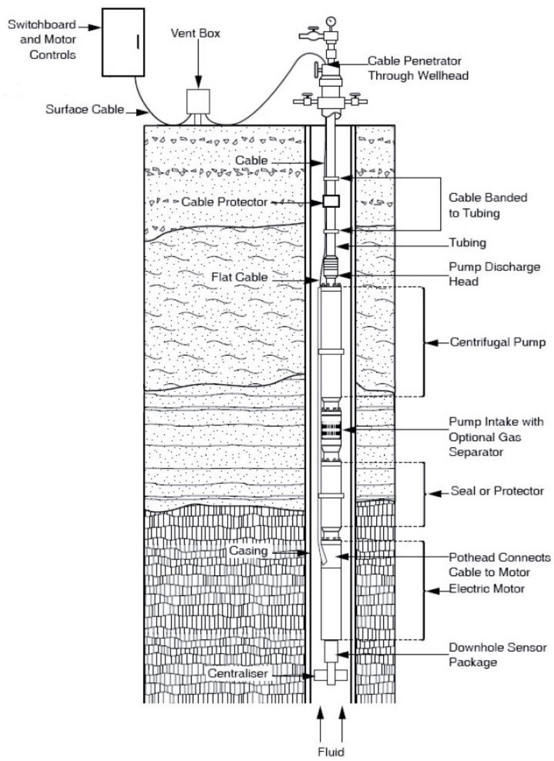


Figure 3.6: *Fundamental view of the ESP system. [25]*

3.2.1 Operation principle

Electric submersible pumps (fundamental design in Figure 3.6) apply pressure to the pumped fluid in the form of velocity. At first, a reverse-flow intake in the pump circulates fluid. Due to reversals, natural separation occurs, and gas is left in the casing annulus. An additional gas separator can be used before the pump intake, but a reverse-flow intake is often sufficient enough, and a gas separator is not required. After that, the oil goes through impellers which pressurize fluid with rotational movement. Impellers are discoidal rollers connected to the shaft of the downhole motor. Since one individual impeller is fairly small, the pump contains several of them, stacked in series. Fluid enters a rotating impeller through an eye at the bottom of the impeller where centrifugal force gains the fluid's velocity. After that, the fluid goes through a diffuser above the impeller. Shape and size of intake and outlet of the diffuser transform the fluid's velocity to pressure. This cycle is repeated in the next stage, and fluid gradually achieves the desired pressure. Movement is illustrated in the Figure 3.7. After pressurizing, the fluid goes to the surface via production tubing (same design principles as presented in Subsection 3.1.3). [9]

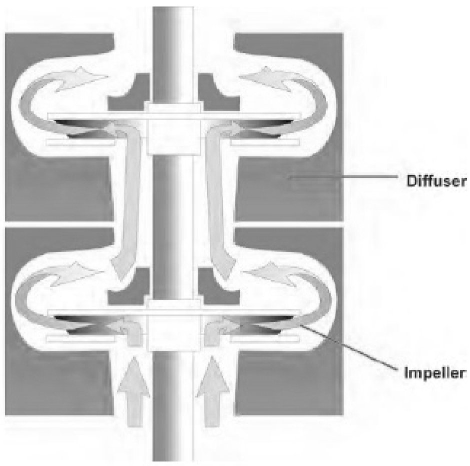


Figure 3.7: *Pressurizing stages in the impeller. [6]*

Detailed radial impeller and diffuser designs are presented in Figure 3.8. Radial design is used when flow rates are small. Other possible geometry is mixed flow design used with higher flow rates [6]. The structure is similar between these two, but the difference is the angle in which fluid goes through the stage. In radial design, movement is mostly perpendicular to the shaft. In mixed design, fluid goes through a stage in parallel and radial to the shaft.

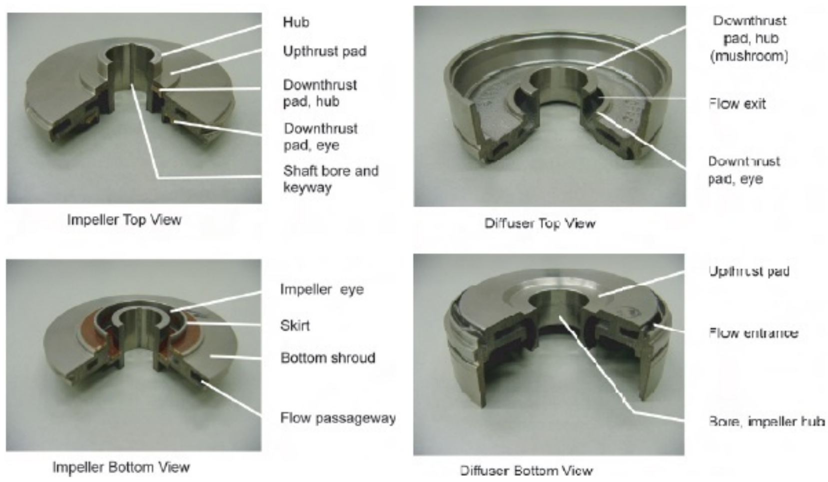


Figure 3.8: *Radial flow impeller and diffuser designs.*

3.2.2 Motor and downhole components

As mentioned earlier, in oil-related ESP systems, the motor is placed under the pump unit. Electric motors used in ESP applications are usually three-phase induction motors [27]. Due to harsh and challenging operating conditions, these motors have particularly good thermal and structural protections. The size of the motors is also minimized to fit into the downhole, as can be seen in a cutaway figure of a basic ESP motor in Figure 3.9.

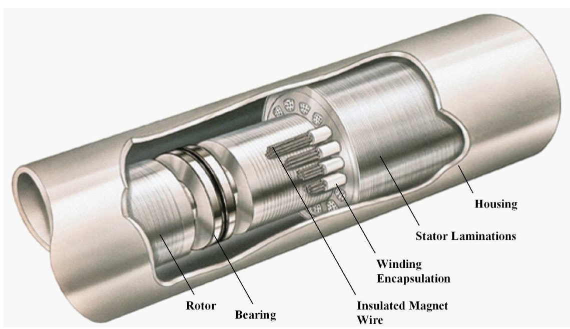


Figure 3.9: *Typical ESP motor design. [27]*

Power to the motor is led via a power cable traveling at the side of pump. The cable is armoured thoroughly to withstand mechanical and chemical corrosion. Especially protection against decompression of the cable screen due to dissolved gases is important. Therefore synthetic rubber materials are not preferred. A layer of metal material, for example lead, is a better way to prevent this kind of chemical corrosion. In the downhole, the cable goes to a pothead which acts as a plug connecting the cable to the motor. The pothead improves reliability and eases the connectivity of the motor and the cable. [27]

The seal chamber is placed between the motor and the pump intake. It has several purposes, but mainly it protects the motor from contamination of well fluids. The seal chamber also equalizes and compensates pressure variations between the motor's interior and the wellbore. Motor oil in the rotor gap might expand due to temperature rises, and then the seal chamber acts as a storage for excess oil. In addition to this, the seal chamber supports the pump's downthrust while it also dissipates generated heat. The structure of the chamber is divided into several different sections. Thrust bearings and a heat exchanger are at the bottom of the chamber. The pump causes a downward thrust which is absorbed by thrust bearings connected to the shaft. The mechanical seal and elastomer bag preventing well fluids from leaking into the chamber are at the top of the chamber. Still, some oil gets past these seals due to pressure differences, which is why a labyrinth chamber is needed. The labyrinth serves as a backup method for keeping motor oil and leaked oil apart. [6]

If downhole equipment is installed very deep, an additional sensor pack might be necessary. It provides detailed information about downhole conditions to surface controllers. Temperature and pressure values at the downhole are often close to the motor and pump safety limits. Therefore accurate information is needed to protect the equipment.

3.2.3 Surface equipment

The surface equipment of ESP system is quite similar compared to the PCP system, with the exception of the motor's location. Production tubing leads to the wellhead which works basically the same way as presented in Subsection 3.1.5. However, the wellhead's frame is simpler since there is no need for rod implementation through it. The motor control equipment is also not straightly connected to the wellhead. The frequency converter, and possible controller attached to it, is connected to the downhole motor with the power cable discussed in the previous subsection.

Depending on the size of the application, medium voltage motors are sometimes used [4]. Then, either a step-up transformer (for low voltage VFC) or a medium voltage VFC is required. Medium voltage converters might be considered with applications pumping large amounts of oil. Low voltage converters are significantly cheaper and therefore the choice for small wells. Due to long cable lengths, sine wave filters are often installed between the VFC and the motor. Otherwise cable losses caused by harmonics would increase significantly. Sine wave filters affect the motor control so that vector control methods cannot be used. It means that scalar control methods are common with ESP applications (more of control methods in Section 3.3).

3.2.4 Power characteristics of ESP

The main considerations while sizing ESP system components are reservoir productivity and fluid properties [10]. Unlike with a PCP system, the motor is at the bottom of the well, and power requirements to lift fluid to the surface are therefore calculated from a different point of view. At first, the productivity of the well is studied with test data. Determining the productivity index PI depends on whether the value of flowing downhole pressure (P_{wf}) is above or below bubble point pressure. Flowing downhole pressure is the pressure in the well at the level of perforations. If the pump intake is at the same level, they can be regarded as the same. Above the bubble point pressure, the productivity index is calculated linearly with Equation 3.6 [25]

$$PI = \frac{Q}{P_r - P_{wf}} \tag{3.6}$$

After PI is known, flowing downhole pressure can be estimated with different production rates Q while reservoir pressure P_r is kept constant.

To define lift requirements, total dynamic head (TDH) is calculated [25]. For this purpose, information of fluid properties is needed. With the knowledge of water cut and gas-oil ratio, the fluid's composite specific gravity (SG_{comp}) is formed. The calculation process combines all specific gravities, taking also into account gas behaviour below the bubble point pressure. Equations for this are presented, for example, in the Petroleum Engineering Handbook [6]. In the process, the percentage of free gas at intake is sorted out. Generally, if free gas amount is above 10 % of total fluid volume, a gas separator at the intake should be used. TDH consists of three components: net well lift (H_L), tubing friction loss (F_t) and wellhead pressure head (H_{wh}):

$$TDH = H_L + F_t + H_{wh} \tag{3.7}$$

Net well lift depends on tubing length (s), flowing downhole pressure and composite specific gravity according to Equation 3.8.

$$H_L = \frac{s - P_{wf}A}{SG_{comp}} \tag{3.8}$$

A is a constant factor of the water column height creating one used pressure unit, if other than metric system is used (for example 2.31 ft/psi). Tubing friction loss is usually calculated with pressure loss per distance - value (S) obtained from Hazen-Williams equation [15]. It is dependent on flow rate, diameter of the tubing and material specific constant. Ready-made tables for friction values are available, but pressure drop can also be calculated with Equation 3.9.

$$S = \frac{KQ^{1.85}}{M^{1.85}d^{4.87}} \tag{3.9}$$

where K is constant (10.67 for metric system or 4.52 for imperial system), Q is flow rate, M is material coefficient and d is diameter of the tubing. Pressure value is converted to corresponding height value similar as net well lift Equation 3.8. Remaining wellhead pressure head is calculated with the knowledge of tubing head pressure (P_{th}) as it is presented in Equation 3.10.

$$H_{wh} = \frac{P_{th}A}{SG_{comp}} \tag{3.10}$$

Pump type is selected to meet the requirements of the desired production amount with good efficiency. Each pump contains performance graphs which help selecting a suitable motor. With the production rate, the head for one stage and required power (BP) are obtained from the pump curve. The number of stages can be then calculated as Equation 3.11 shows [8].

$$\text{stages} = \frac{TDH}{head/stage} \tag{3.11}$$

The power requirement of the motor is finally calculated as it is presented in Equation 3.12. The resulting value takes account only power related directly to lifting. Depending on the final assembly of the pump system, a higher power rating is needed since sealing, possible separators etc. require additional power. Nonetheless, this value gives a good starting point for motor sizing. [8]

$$BP_{total} = \frac{BP}{stage} \times \ stages \ \times SG_{mix} \tag{3.12}$$

3.3 Varible frequency converter

Since this thesis aims to improve the application program used with the AC-AC voltage-source variable frequency converter, this section gives an overview of the basic concept and structure of it. Generally, the converter is a part of a variable frequency drive (VFD), which consists of the converter and an electric motor. The main function of the converter is to convert constant frequency input AC voltage to the appropriate output AC voltage and frequency for the motor. Voltage-frequency rate is proportional to the rotation speed of the electric motor, so the motor's behaviour can be controlled based on that. In addition to speed, the torque of the motor can be controlled if enough feedback data from the motor to the converter is available. However, any feedback is not necessarily required for the simplest operation.

3.3.1 Structure

The main parts of the frequency converter are the rectifier circuit, the inverter circuit and the DC-circuit between them. The design of the bridges depends on what kind of voltage is fed to the converter and which type of electric motor is used. Basic industrial and general purpose frequency converters (like ACS880) are meant to operate with standard supply voltages and control mainly three-phase induction motors. For this purpose, the rectifier circuit is usually a full-wave diode bridge consisting of six diodes or thyristors, two for each phase. The inverter circuit for the same intention consists of IGBT-pairs for each phase. Bridges are digitally controlled with the PWM-technique. The DC-circuit between bridges has a capacitor which trims the ripple occurring in converted DC-voltage.

The above described parts enable the key operation of the converter. In practice, several other components are included to the design to achieve better performance. At the supply side, there are usually some passive filter to smooth voltage spikes and a line reactor to protect the converter from current spikes. A possible filter to reduce electromagnetic noise might be also installed at supply side. A braking chopper required by the dynamic braking feature is connected to the DC circuit, as well as a braking resistor. At the output side, a sine wave filter or du/dt filter protects motor from voltage spikes. A protective reactor can also be connected to the output side.

Component selections determine the performance factors of the frequency converter, but a human-machine interface design is also a significant part of the converter and the whole drive. For example, commissioning and application configuration is done via a converter interface. This includes applying converter specific settings, application related data and motor parameters. Parameters link to each other and eventually determine how the converter controls the motor in any given situation. That is why a clear converter software interface is essential. The converter should be easily configured, for example, via a control panel in the front of the converter. Ease of use and interface options are often a significant selling argument and therefore should be considered sufficiently during the design process.

3.3.2 Motor control methods

The motor control method determines how the frequency converter identifies the motor and gives control variables to it. Depending on the method, the information path is either two-way, meaning that the converter receives feedback of the motor's status, or the motor is controlled blindly without data of the motor's actual conditions. The amount and type of feedback affects how quickly and accurately the converter can control the torque and speed of the motor. Control methods are divided into two main categories: scalar control and vector control.

Scalar control

The scalar control method uses frequency and voltage as control variables. The user defines the appropriate references and the converter feeds them to the motor. There is no feedback from the motor to the converter required, so control is based on predetermined motor and application properties, i.e. open-loop control. In practice, the converter gives references to a modulator which forms a sine wave of them. The wave is fed to the motor's stator windings, causing rotation to follow that signal. This method is cheap and easy to implement [11]. On the other hand, the accuracy of the control suffers from the lack of feedback and the use of a modulator causes a delay in response times. Since the motor status is ignored and torque cannot be controlled, this method is not suitable for applications requiring high reliability.

Vector control

Field-oriented vector control (FOC) is a basic vector control principle. Vector control methods take motor status in account when giving control variables to the motor. This requires feedback on rotor speed and angular position. With the feedback and given motor data, the converter forms a motor model and can therefore give more accurate and dynamic control variables. Control variables, such as voltage, are then fed to the motor through the modulator similarly to the scalar control method. Since motor information can be used, torque can be controlled, though indirectly due to the modulator. This is advantageous especially at start-up because high torques can be safely used to achieve effective acceleration. Therefore, vector control is used with more challenging applications like cranes. On the other hand, feedback implementation requires additional devices, which naturally increases costs. Vector control is electrically far more advanced and therefore complex to design compared to scalar control. Motor modelling and signal processing requires more engineering in this case, but it is also well-known technology.

A more advanced concept of vector control method is direct torque control (DTC). Compared to field-oriented control, torque response time is only a tenth [11]. Reduction in response times can be explained with the absence of a modulator in the control loop. DTC control variables are actual values, thus processing and modifying the signals do not increase the response time. As the control variables are obtained directly from the motor, feedback encoders are not necessarily needed. In addition to a fast response time, static and dynamic speed accuracies are very high with DTC. Static speed accuracy means the difference between the actual motor speed and a given speed reference. Static speed accuracy is, depending slightly on the motor power, a few tenth of percent while the FOC obtains a static accuracy of a few percent [11]. Dynamic speed accuracy indicates the ability to recover from load changes. The rate between the dynamic speed accuracy of DTC and FOC is roughly the same as with the static accuracy [11]. These can be further improved by using additional feedback devices.

4. RESEARCH MATERIAL

Research material to identify the development need for the current application program is compiled in this chapter. The first section consists of a competitor analysis of ABB's main competitors. Another section presents the survey that was sent to ABB representatives in different countries. That way, more information of customers' needs can be obtained and development goals determined more precisely.

4.1 Existing control solutions

ABB's newest Progressing Cavity Pump and Submersible Pump application control program is designed to operate with the ACS880 low voltage industrial drive. The program utilizes the functionalities of standard drive software added with some dedicated PCP and ESP functionalities. Partly the same functions are used with both applications. The biggest difference between the functionalities of these two is the motor control. Due to requirements of a centrifugal pump, an attached sine wave filter in drive system prevents the use of the direct torque control method. In addition, a medium voltage motor is sometimes needed in ESP applications and that is why some competitors offer medium voltage frequency converters as an ESP control solution. Performance, and usually functionalities, of medium voltage converters are generally better compared to low voltage converters. On the other hand, medium voltage converters are more expensive and might be a significant expense in smaller sites.

Altogether, the competitors' offering varies widely. An application control program, as ABB has, is only a one approach. Some competitors, Siemens and Schneider for example, offer only an application programming possibility with prepared application specific functions. As a result, the control program is more modifiable compared to ready-made software and can be changed thoroughly according to needs. Due to inconsistent properties and conditions of each pumping site, it is beneficial that the program can be modified this way. On the other hand, commissioning requires more engineering since customers need to familiarize themselves with the development environment, for example, Codesys. Another possible solution is to use a pre-programmed controller attached to the drive. It means that all pump feedback signals go to a separate controller unit where they are processed. The controller then gives speed reference and stop or start commands straight to the VFD. The application is configured by a controller which is either embedded or physically separated from the drive unit. This brings flexibility to drive selection. Practically this leads to the same outcome as using ready-made software. The controller solution is hardware-based, so it is easier to extend with I/O extension modules, fieldbus adapters etc. These might be useful if operating many units simultaneously.

The following subsections give an overview of individual competitors regarding their offerings of PCP and ESP application control solutions, as well as presents ABB's current application program. A detailed table of compared functionalities is presented in Appendix A. The presented information is received from public marketing material, product manuals and datasheets.

4.1.1 ABB

One of the main features ABB's PCP application control program utilizes is advanced motor control. The direct torque control method is used in standard ACS880 software as well, but it is emphasized when dealing with demanding applications. The electric submersible application program uses ACS880's scalar (alternatively frequency) control method.

Protection functions prevent the pump system from exposing to conditions which may cause excess wear or pump failures. The backspin control function is one of these preventative functions. Backspin is motor's rotation in a reversed direction caused by descending oil in production tubing after motor's normal operation stops. Backspin might last for hours since an oil well could be several kilometres deep [12]. If backspin is not controlled, rotor speed might rise above resilience limits and scatter either the pumping unit or surface components. Even if the components usually are designed to withstand backspin, descending oil is lost production. ABB's program monitors the speed of the rod in shut down situations. The backspin function keeps the acceleration rate and speed of the reverse rotation below the defined limits.

The program is equipped with the ability to monitor and react to high temperatures and pressures occurring in different sections of the pump. External sensors are usually placed into the critical parts of the system: discharge outlets and down at the wellbore. However, torque protection can be effectively carried out also sensorless if the DTC method is used. Overtorque situations usually occur when sand or rock particles resist the rotor's movement or oil viscosity suddenly changes. The speed of the rod is then automatically lowered to reduce torque so that the shutdown of a whole pump would not be necessarily required. In breakdown situations, the torque increases rapidly to a high value, for example, after the stator elastomer rips. When torque rises above a certain limit, the pump is immediately shut down to prevent additional damages. The program has two different limits, so both of these cases can be monitored simultaneously. Underload situations occur when the fluid level in the well suddenly drops or a gas pocket displaces oil near a pump intake. Significant underload might also indicate a broken rod. The PCP program activates an underload function if the rod speed increases enough while the rod torque stays constant. The underload limit is defined by creating a three point curve. The program reacts if the point of current values is below the curve by shutting down the pump or giving a warning. This prevents excessive rod speeds from forming. Limits are set according to application and properties of the well, for example, well depth, API gravity and so forth. With the scalar control mode, torque protections cannot be carried out as effectively, because torque readings are only estimations. The principle is same as in DTC mode, but accuracy is not as good.

While a pump operates at the allowed range of protective functions, control functions optimize production. The control functions of ABB's control program concentrate mainly around the well fluid level. The main feature of the program is a fluid level control function. The aim of the function is to keep the fluid level in the well constant at the value where yield is at the highest. At the moment, the level is received from a fluid level sensor or calculated based on pressure data. The level value is then fed into the PI controller which makes speed changes to obtain its set point. The program can activate sleep mode if the fluid level either falls or rises past a certain point where it is not productive to pump. The pump is not shut down entirely, but it still monitors the fluid level and continues operation after the level is back within the defined limits.

Start-up is a critical phase during pump operation due to fast torque changes. Normally, motor acceleration from zero to reference speed is scaled to last around ten to twenty seconds. With an application like the PCP, longer acceleration times are needed. The control program can be set to accelerate the motor to reference speed in two stages. In the first stage, speed is increased linearly for up to ten minutes. The slow start protects the pump components, preventing unnecessary wearing. For example, oil acts as a lubricant and it has not yet reached the upper parts of cavities straight after the start. The program also contains a jogging function, which is particularly useful if conditions are sandy. The jogging sequence runs the motor back and forth, cleaning the pump. This, however, requires a manual start at the moment.

4.1.2 Unico

Unico has similar application control programs as ABB, and they are used with 1100-series standard drives. They have gained success especially in South America. The control principles are built around more detailed models compared to ABB's program. While ABB's program requires instrumentation for fluid level and flow control, Unico's pump and reservoir models can make estimations of them without sensors. This, however, requires accurate pump and reservoir data.

Unico's PCP program gives estimations of pump intake and outlet (flow), well inflow, fluid over pump and fluid level. Pump intake and flow estimations are based on pump parameters listed in the control diagram in Figure 4.1. The pump model makes an estimation of differential pressure, which is the difference of intake and discharge pressures, correlating to fluid flows. After reservoir-related parameters are included to the model, tubing and casing pressures can be estimated as well. This gives information about the fluid level. Then again, comparing pump intake and casing pressures, the fluid amount over a pump can be calculated.

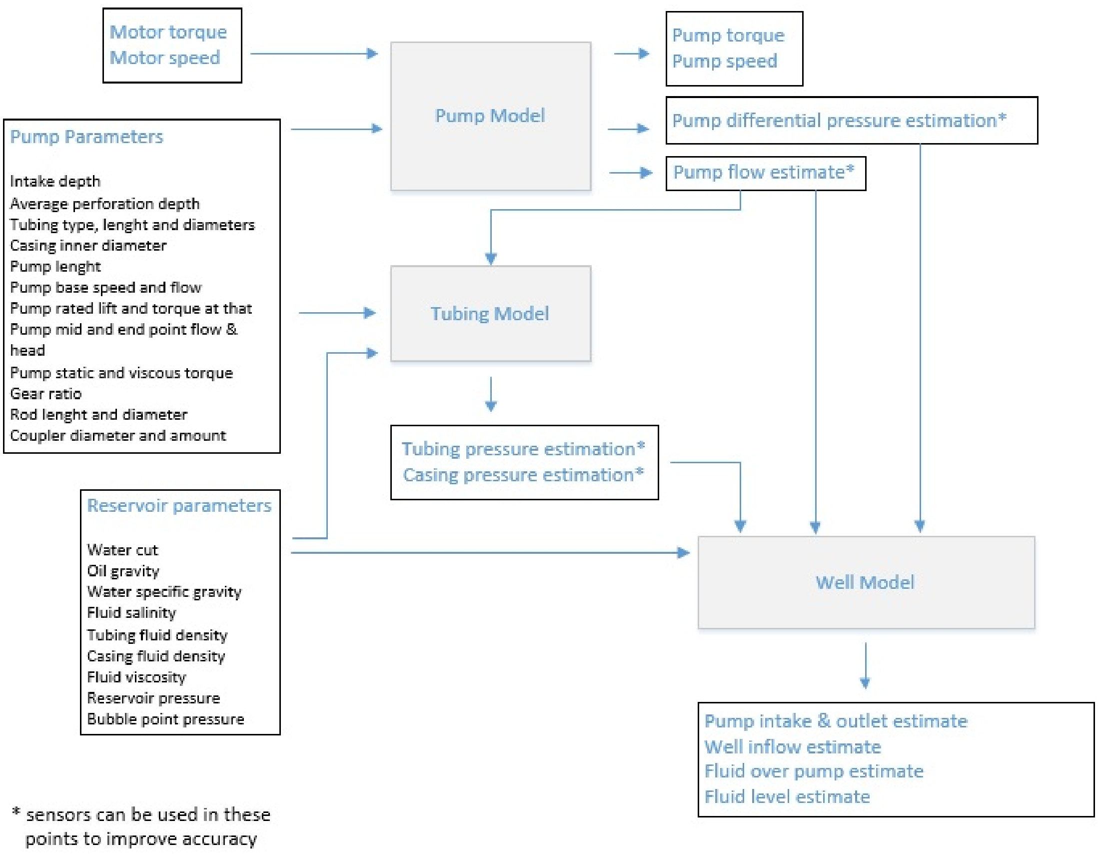


Figure 4.1: *Unico's sensorless control diagram.*

The pump is controlled based on either flow or fluid level. In flow control mode, pump speed is increased or decreased to keep flow constant. The program gives separate production amounts of oil, gas, water and salt, if fluid composition is known. Monitoring features are comprehensive even without a separate monitoring tool. Fluid level control keeps fluid levels in a reservoir, or alternatively in a discharge tank, within the set limits. The pump can be also set to operate at certain times by using the program's calendar and timer functions.

As it is mentioned in the control diagram, sensors improve the accuracy of control. Temperature sensors are not necessary for control purposes, but for protective reasons, they can be set to monitoring casing, tubing and fluid temperatures. In contrast to ABB's PCP program, Unico's backspin function includes a power survival mode. This means that in power cut situations the pump system stays powered with energy generated by rotor movement. Their torque protection function uses static limits to cut power to the motor, so there is no automatic speed reduction in case the torque limits are exceeded. A backflush function, however, can be activated if torque rises above the set limit. The function activates a back-and-forth run sequence in order to remove sand or other particles stuck in the pump.

Unico's ESP control program uses similar control and monitoring principles as the PCP program. Flow and pressures are estimated based on reservoir and pump models. Other control variables are again derived from these values (similar control as in Figure 4.1) if sensors are not used. Their ESP program has also models for a transformer and cables. Pump control can be based on flow, intake pressure or fluid levels. Each has their own advantages and are suitable for different situations. In addition to different control options, the program uses multiple constraint optimization. This means that it automatically varies production constraining limits (e.g. torque and pressure) so that the system is not always working on the upper level of one specific limit. This divides the system's load more evenly.

Protection functionalities in Unico's ESP program are comprehensive because different sections of the pump can be individually monitored. Pressure and high torque limits can be monitored without sensors, but temperature monitoring requires external sensors. Low torque and speed situations are also monitored. Low speed might indicate stall conditions and low torque could mean a plugged sand filter. Unico's ESP program has good production monitoring and estimation features, but it lacks cleaning functions. There are no start-up routines like rocking start or other programmable sequences as in their PCP program.

4.1.3 Lufkin and Kudu Industries

Lufkin Industries has a controller solution for PCP applications. It also offers the same controller embedded to a VFC. Lufkin's Well Manager controller has a pretty basic control principle that is based mainly on flow monitoring. Speed is increased as long as it increases the fluid flow. Naturally speed and torque limits are set to protect the pump. Flow limits can be also used if flow is wanted to be kept within certain values, even if the pump could produce more. Lufkin's controller requires a flow sensor, meaning that sensorless operation is not possible. The control loop is presented in Figure 4.2.

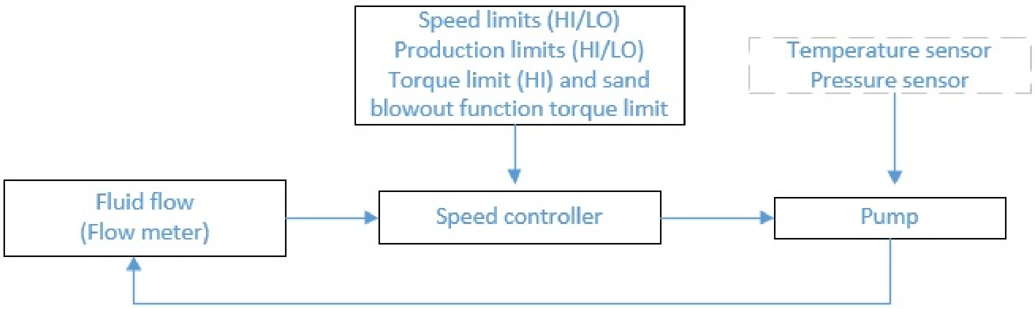


Figure 4.2: *Control diagram of Lufkin PCP controller.*

Depending on type of a flow sensor, discharge pressure and flow temperature can be monitored simultaneously. The controller has input for only one temperature and pressure signal, which weakens the overall supervision of pump conditions. Similar to Unico's PCP software, Lufkin has an automatic sand blowout function that is activated if torque rises above a certain limit. Calendar-based operations are also possible. Lufkin's advantage is a long acceleration ramp which can be set up to one day. Then again, the controller lacks a backspin control function, which is found in every other solution.

Kudu Industries has a similar PCP controller embedded to a VFD. It uses identical control algorithms, but additionally has rocking start and backspin control functions included. Since Kudu is part of Schlumberger, it seems that Kudu has specialized on PCP applications while Schlumberger has concentrated on ESP solutions. Kudu is an especially strong player in North America. Lufkin, being a subsidiary of GE Energy, has a big role in providing pump equipment more widely as a part of GE's artificial lift chain.

4.1.4 Yaskawa

Yaskawa has an oil-pumping application program for the A1000 drive. The program has features which are suitable for PCP, ESP and also beam pump applications. It has only the essential features to cover basic PCP and ESP operation, and it uses a user-defined torque or frequency set point as a reference for the pump motor. High and low pressures, as well as high temperatures, can be monitored with individual sensors and the program shuts down the pump after a delay if the set limits are exceeded. During start-up, the program monitors the acceleration time. In case the acceleration time to the set minimum speed is slower than defined, a low speed fault occurs. That might indicate a stall condition caused by a locked wellhead or excessive rod friction. Start-up can be also done in steps to prevent excessive sand from being sucked into a pump. Undertorque detection and backspin control functions are intended especially for PCP use. When the torque value falls below the limit, the converter gives a frequency boost to the motor to get excess oil out of the pump before shutting it down. The delay time between the detection and the boost prevents unnecessary shut-downs. The application program has also a custom run sequence with a programmable start so that it can be either manually or automatically started. It is used for the same maintenance purposes as the sand blowout and backflush functions. Otherwise the control program does not have any application specific functions like fluid level or flow control.

4.1.5 Danfoss

Danfoss' solution is to use a controller in connection with VLT Automation low voltage drives. A Sensorless Artificial Lift Technology (SALT) controller is embedded to the drive, and the application is controlled normally via the converter's interface. Thus, for users, it is the same as using a VLT drive with slightly different software. The same solution is used for PCP and ESP applications. Emphasized features are production optimization, which automatically varies speed based on production amounts, and gas pocket detection. After a gas pocket is detected, the pump tries to purge gas through the pump before reducing speed to minimum. Level control with SALT is also possible. One unique feature that Danfoss has is the monitoring of adjacent wells and taking that into account in the level control. Sand-purge and torque limiting functions are useful with PCP applications where these functions reduce overall wearing of the pump. The sand-purge function runs the pump to a different direction compared to the gas handling principle. In addition, the software keeps track of production amounts and other events in a thirty-day log.

4.1.6 Vacon

Vacon's NXP drives are generally used with oil applications. For PCP and ESP applications, the software is a bit modified, but there is no mention of dedicated application control program like Vacon has for beam pumps. However, speed (and torque in case of PCP) is controlled based on measured conditions, for example, flow or pressure. Indirect downhole pressure and temperature estimation is also mentioned, but detailed information of what surface measurements it requires, is not available. It also remains unclear whether it is possible to include these estimates to a control loop, or if they exist only for monitoring and safety purposes. Solutions also feature a backspin control function with power survival-mode. Monitoring possibilities are limited only to system pressures and temperatures.

4.1.7 Toshiba

Toshiba offers a Plus Pack low voltage drive for ESP applications. Another solution is the TM300MVi medium voltage drive. It does not require a step-up transformer and has better overall performance, but it does not have similar, ready-made ESP specific functionalities like the Plus Pack. The Plus Pack controls ESP either on the basis of flow or pressure at pump intake. Flow values are obtained with external sensors and speed increased or decreased to achieve either the maximum production level or a defined set point. If pressure is the main control variable, the goal is to keep the intake pressure at the downhole constant with appropriate speed changes. This reduces gas locks and pump off. With knowledge of the intake pressure and flow values, leaks in sealing can also be detected. Intake flow can be derived from the pressure values, and the mismatch between intake and surface flow indicates leaks in some part of the pump. Other pressure and temperature measurements for protection purposes are possible, although the control software lacks separate named parameters for different sections of the pump (e.g. casing or tubing).

The scalar control method gives some limitations to start-up since torque cannot be directly controlled. The drive can automatically apply a frequency boost to ease a start of high loads. This boost is defined in advance since there is no feedback in the control loop to provide information about the state of the motor. Speed estimations are still monitored constantly, and the software has a function to detect abnormal speeds in different situations. The Plus Pack also has a rocking start function, which cleans the pump at start-up. It also has a power ride-through ability in case of short time power cuts.

4.1.8 Baker-Hughes

Baker-Hughes' newest dedicated VFC for ESP applications is the Electrospeed Advantage. It is developed by Centrilift, which currently operates under Baker-Hughes. Its motor control method is scalar, although it is marketed as "real-time torque command". In practice, it probably is similar to ABB's scalar control method where some enhancements are made (e.g. IR-compensation, slip estimation etc.). Torque readings are not, in this case either, taken straight from the motor shaft and the over torque and overspeed protection function uses only estimations. External sensors are required to achieve pressure and temperature values. Baker-Hughes offers compatible plug-and-play sensors, as it also offers a full scope of other oil production related products. Electrospeed Advantage has a hard start functionality, which means a similar predefined frequency boost as in the Toshiba Plus Pack.

Electrospeed Advantage's production optimization algorithm keeps intake pressure constant. It has power ride-through and fluid level control functions as well. In addition to these, the converter controls rapidly changing events in a way which creates minimal effect to reservoir. In practice, this means that if downhole pressure optimization is not used, there is a limiter to prevent too rapid speed changes so that unexpected situations in the reservoir will not happen.

4.1.9 Schlumberger

The Schlumberger Speedstar SWD drive with an integrated sine wave filter is designed for ESPs. The speed of the motor is controlled to maintain either stable load or intake pressure. Load optimization is preferred if downhole instrumentation is available. In sudden overload situations, the speed is automatically reduced to avoid total shutdowns. The power ride-through function also prevents nuisance trips. SWD's start-up ramp can be programmed according to application needs. The acceleration rate can vary from 0.01 Hz/s to 1 Hz/s and speed is monitored in case of the stalling condition. The rocking start function can also be executed to get excess sand out of the pump.

4.1.10 Other

As already mentioned earlier, Lufkin is a part of GE, and it seems that PCP products are largely its responsibility in the coalition. However, GE has launched a new Vector Plus drive, which is dedicated to ESP applications. There is not very much information available about the drive, but it is presumably going to be a strong competitor for ABB.

Siemens is one of ABB's main competitors also in the field of oil and gas. Siemens does not have similar ready-made application software. However, it offers a wide range of application programming possibilities and has comprehensive tools to execute this, for example, with the Step7 software. Compared to ready-made software, this approach requires additional logic controllers and commissioning, and the ease of this depends largely on the available programming tools and software. In addition to good application programming ability, Siemens' drive offering is very wide, covering all kind of application needs. The usual choice for low voltage PCP or ESP applications is the G180 general purpose drive. For medium voltage applications the GM150 is often used.

Similarly to Siemens, Schneider and Rockwell Automation lack dedicated oil application programs and rely on application programming. Schneider's SoMachine software environment can be utilized to engineer applications, mainly for the Altivar 71 drive in this case. Rockwell has several software options for this purpose, for example, the Studio 500. For smaller low voltage applications, Rockwell uses the Powerflex 700 drive. For more demanding use, such as big ESP applications, the Powerflex 7000 medium voltage drive is a preferred choice.

4.2 Survey

To obtain first-hand information about customer needs, ABB representatives from strong oil industry areas were contacted. Inquiry respondents were asked about the functionalities of PCP and ESP application programs. Opinions on how frequently some functions are asked for by the customers and how necessary they see the development of these functions were the main focus of the survey. Asked topics were formed mainly based on the competitor analysis and discussions with experts working in R&D and sales here in Helsinki. Responses to the survey were received from product managers working locally, for example in Russia, Brazil and Canada. A lot of content was also obtained straight from product managers and the product development team in Helsinki.

4.2.1 Survey results

The main subjects of the requested functionalities are quite consistent. Open-loop pumping, i.e. better pump models and operation based on estimations, is widely asked. The most important part related to that would be to eliminate the need for downhole sensors. This means that new functions, for example, fluid level estimation, have to be developed. Improvements for the sand cleaning function are also demanded, both at start-up (rocking start) and during normal operation. Production monitoring enhancements is also one consistently requested development area. One of the challenging requests that emerged is motor control and supervision updates to ESP mode. In practice, the DTC method is wanted also to work with ESP applications where a sine wave filter and a possible transformer are used. Better thermal supervision and control is requested due to challenging pumping conditions of ESP applications where the pump is constantly at the edge of its sustainability.

One of the requirements which occurred with only some of the answers is gas pocket detection. It seems that it is not as important in all applications similarly to the power survival mode during power outages. Improvements to start-up behaviour are also asked for in some cases. A need for longer acceleration ramps and their monitoring depends a lot on the conditions of the individual reservoir, but it was also seen as one possible improvement. All received requirements are combined into Table 4.1.

Table 4.1: *Received development requirements and suggestions.*

Requirement	Clarification
Open-loop pumping	The program would form estimations of different variables based on models and already measured values. Every enhancement would count and give value to customers even if comprehensive models could not be done at once.
Sand cleaning function	Cleans pump of excess sand at start-up and/or during normal operation.
Gas Pocket detection	Detects abnormal amounts of gas in the wellbore and reacts by changing pumping speed.
DTC motor model and thermal supervision improvements to ESP mode	A direct torque control method with a sine wave filter and a transformer. Thermal supervision requests mainly mean improving the motor's thermal supervision. From the converter's point of view that could mean, e.g. some preventative maintenance notifications.
Production monitoring	The flow of oil and gas, as well as inferred production amounts, should be possible to monitor straight from the program interface.
Power survival mode	In case of a power outage, a backspinning PCP rotor generates energy so that system keeps powered.
Programmable acceleration ramps	The shape and time of the acceleration ramp could be determined more precisely.
Stall detection at start-up	A stuck or broken pump could be detected during start-up by monitorign the speed of the pump and comparing it against calculated speed.
User-definable U/f-curve	A voltage-frequency curve would improve the accuracy of the scalar control mode. This should be modifiable without shutting down the pump.
Macro sets and parameters for application specific motors and other components	The standard program contains ready-made parameter sets for asynchronous motors, for example. It would ease commissioning if similar sets were added to different motors and components used with oil applications (EX and PM motors, sine-filter and step-up transformer, for example).
Real time clock	Scheduled operations (e.g. activation of cleaning routine) could also be implemented based on the clock.
Brake confirmation for hydraulic brakes	The current mechanical brake confirmation routine before start-up could be extended for hydraulic brakes as well.

5. APPLICATION CONTROL PROGRAM DEVELOPMENT

This chapter focuses on the development of ABB's PCP/ESP application control program, and the technical implementation of functions will be discussed more specifically. Sections give a good overview of principles and considerable matters around each functionality. The purpose of this chapter is to give design guidelines for different requested functions, not to give final solutions for design. Based on this, it is easier to start the development process in practice. However, in some cases the following presentations give a fairly accurate overview of the physics behind the individual functionality.

5.1 Fluid level estimation

At the moment, determining a fluid level in a well requires a downhole sensor. Either a direct fluid level sensor or alternatively a pressure sensor is suitable for that purpose. The level value from the pressure sensor is simply derived using the hydrostatic pressure formula. The compound columns above the oil need to be taken into account when using the pressure value. Oil produces a much bigger pressure compared to a similar height gas column, so only significant amounts of excess gas can lead to influential pressure changes. Furthermore, pressure changes caused by gas are often just momentary and the speed controller is therefore set to moderately react to changes.

When designing a function which estimates a fluid level without a downhole sensor, motor torque is the key factor. PCP and ESP systems differ from each other in this sense, thus the following principles apply only to PCP. As is presented in Subsection 3.1.7, sufficient torque to overcome differential pressure combined with friction losses is required to lift fluid. Since hydrostatic pressure inside the tubing (and also casing) affects how big the differential pressure is, torque change with a constant flow or speed tells about the change in fluid level. Thus, a fluid level estimation is derived with the help of hydraulic torque. The earlier presented net lift Equation 3.1 shows that it consists of difference of discharge and intake pressures. Intake pressure can be divided to sum of casing head pressure (P_{ch}), hydrostatic pressure of gas inside the casing (P_{cg}) and hydrostatic pressure of liquid column inside the casing (P_{cl}):

$$P_i = P_{ch} + P_{cg} + P_{cl} \tag{5.1}$$

Casing head pressure can be estimated to be atmospheric or zero. Hydrostatic pressure consists of the density (ρ) of the fluid, gravity (g) and length of the column. Gas column length is the same as the fluid level (L) from surface and liquid column is the difference of intake depth (s) and the fluid level. Other than the value of the fluid level being constant, Equation 5.2 presents intake pressure as a function of the fluid level.

$$P_i = P_{ch} + \rho_g \ g \ L + \rho_l \ g \ (s - L) \tag{5.2}$$

A similar breakdown applies to discharge pressure. It consists of tubing head pressure (P_{th}), hydrostatic pressure of the liquid column inside the tubing (P_{tl}) and flow losses inside the tubing (P_{loss}) as the following Equation 5.3 shows.

$$P_d = P_{th} + P_{tl} + P_{loss} \tag{5.3}$$

$$P_d = P_{th} + \rho_l \ g \ s + P_{loss}$$

Tubing head pressure is the pressure in the wellhead before the flow line. This pressure is usually supervised, and in this case, defined as a known value. Overall, it is challenging to estimate due to its dynamic behaviour. Hydrostatic pressure follows the same formula as in Equation 5.2. Flow losses are also difficult to determine precisely since high density fluids do not act as linear Newtonian fluid [8]. Centralizers and rod guides inside the tubing also bring challenges to the estimation. Linear, called also laminar, flow losses can be defined for lighter crude oil based on Equation 5.4 [6].

$$P_{loss} = \frac{64}{Re} \frac{d}{} \frac{\rho_l v^2}{2} s = 32 \mu v s \tag{5.4}$$

where v is the flow rate and μ is a dynamic viscosity of the fluid. Re in the equation is the Reynolds number, which takes into account the viscosity of fluid at a given speed. After the Reynolds number rises enough, fluid does not act linear anymore, thus flow is turbulent. For practical estimation, some percentage of losses is defined as laminar and other as turbulent. Flow losses can be estimated with some constant value if pumping depth is not very deep. For a kilometre-deep well, flow losses can already be half of the discharge pressure, so it definitely must be considered more precisely.

From these equations, the fluid level from surface can be estimated based on applied total torque (presented earlier in Equation 3.3):

$$L = \frac{T_{total} + T_{friction}}{VCg(\rho_l - \rho_g)} + \frac{P_{ch} - P_{th} - 32\mu vs}{g(\rho_l - \rho_g)} \tag{5.5}$$

To add this function to the control program, more initial information via parameters is required. Torque value is available at the moment, either as an actual value or estimation. Tubing head pressure and flow rate are also received as actual values from surface sensors. This leaves friction losses (static and system), displacement factor, densities, tubing length and dynamic viscosity as user-given parameters. Friction torque can be calculated through hydraulic torque, being for example 20 % of it at rated pressure, or given as a constant value. A friction increase over time must be also considered. Default values for densities and viscosity can be set based on some common API gravity, and the values are then adjusted according to more accurate information. To obtain the displacement factor, it might require linear approximation based on lift capacity at rated values. Necessary parameters required to estimate fluid levels are presented in Figure 5.1

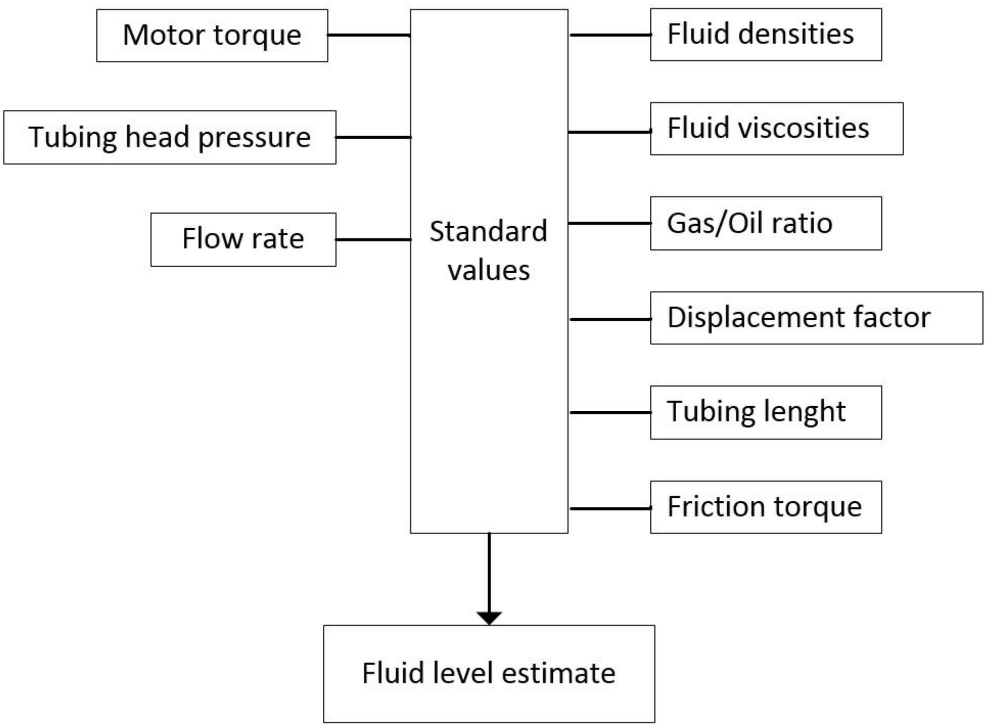


Figure 5.1: *Fluid level estimation parameters. Dynamic values on the left and static values on the right.*

5.2 Optimal fluid level finder

There are two approaches to evaluating optimal fluid levels in a well. The first way is simply to find the level where outflow at the wellhead is at its highest (using, for example, the motor's nominal torque). This requires test data from various levels and is not a very practical solution. Another principle is to estimate the optimal fluid level based on well inflow performance. Well inflow and the maximum production capacity depends on the ratio of static reservoir pressure and flowing downhole pressure. This means that casing pressure, and eventually the heights of fluid columns, determines the maximum production rate (Q_{max}). Under two-phase conditions, Vogel's inflow performance relationship (IPR) can be exploited. This empirical formula is presented in Equation 5.6 [15].

$$\frac{Q}{Q_{max}} = 1 - 0.2\frac{P_{wf}}{P_r} - 0.8(\frac{P_{wf}}{P_r})^2 \tag{5.6}$$

When determining the maximum production rate, the value of reservoir pressure, current production rate and flowing downhole pressure is needed. Static reservoir pressure could be a user-defined parameter in the control program. Production is either estimated or received from an actual flow sensor. Flowing downhole pressure can be derived from a fluid level estimation (or actual value if a sensor is used). For flowing downhole pressure, the depth of perforations (s^*) is needed, so excess hydrostatic pressure beyond pump intake is also considered. After the maximum rate is known, production amounts with different flowing pressures can be calculated. The algorithm in the control program could calculate production estimates with various flowing downhole pressures and derive the target level from the pressure giving the maximum production value. This way the actual testing and searching time could be reduced. A relation between fluid level and flowing downhole pressure is shown in Equation 5.7

$$P_{wf} = P_{ch} + P_{cg} + P_{cl}* \tag{5.7}$$

$$P_{wf} = P_{ch} + \rho_g g L + \rho_l g(s^* - L)$$

$$L = \frac{P_{wf} - P_{ch} + \rho_l g s^*}{g(\rho_g - \rho_l)}$$

As seen, the relation is almost the same as the relation between pump intake pressure and fluid level. Only the height difference between intake and perforation depths makes a difference.

5.3 Gas pocket detection

The current underload function might need updating if new features are added to control program. The underload function should be able to identify different situations so that the right corrections can be made. It would also be beneficial if the function wasn?t based on static torque and speed values. This new presented principle is meant to use when fluid level estimation is used. If fluid level is measured, it is easier to identify gas pockets since they cannot be confused with fluid level changes.

When gas enters the pump intake, it displaces volume from liquid production. If it is not taken into account, it distorts the pump control. A gas column inside the tubing reduces hydraulic torque, and it can be easily confused with a fluid level rise in the well. The key to correct control is to monitor how quickly changes happen and to make estimations based on that. Fluid level changes can be assumed to happen pretty moderately while the effect of gas pockets can be seen very quickly.

Gas inside the tubing reduces hydrostatic pressure compared to situations when the tubing is filled fully with liquid. Excess gas inside the casing also reduces intake pressure. This means that when operating at constant torque, the flow briefly drops. After enough gas has flown into the tubing, the flow rate increases. This happens approximately when pressures caused by excess gas are equal in the tubing and the casing. Gas affects tubing losses and friction as well, so it does not happen exactly then. This same effect can be seen by monitoring torque change if the motor is operated at constant speed. At first, the torque rises when gas is in the casing. After it starts to fill the tubing, the required torque decreases as the loading drops. Depending on the pumping depth, it may take a long time before the gas is noticed at the surface. Thus, it is important that gas pockets can be detected at an early stage.

In Figure 5.2 is a suggestion of how the gas pocket detection could be designed. The change (flow, torque or both) is compared against the defined line. In the case of flow monitoring, if the change over a specific time is above the line, the gas pocket detection function is activated. Then the pump speed is automatically lowered. If monitoring is based on torque, the gas pocket detection function is activated when the corresponding value is below the defined line. Before lowering the speed, a gas-purge done with fast acceleration can be tried in order to get the gas moving fast through the pump. Outside the activation range, control program operates as it is normally set, for example, controlling the fluid level. When considering a practical implementation, the line can be either user defined or working based on a default setting. The length of the tubing affects significantly how fast the change happens. Therefore the line is adjusted steeper as tubing length shortens. To design this kind of functionality, the behaviour of the pump system in case of gas pockets needs to be examined more thoroughly. The only way to do it effectively is to do some practical testing.

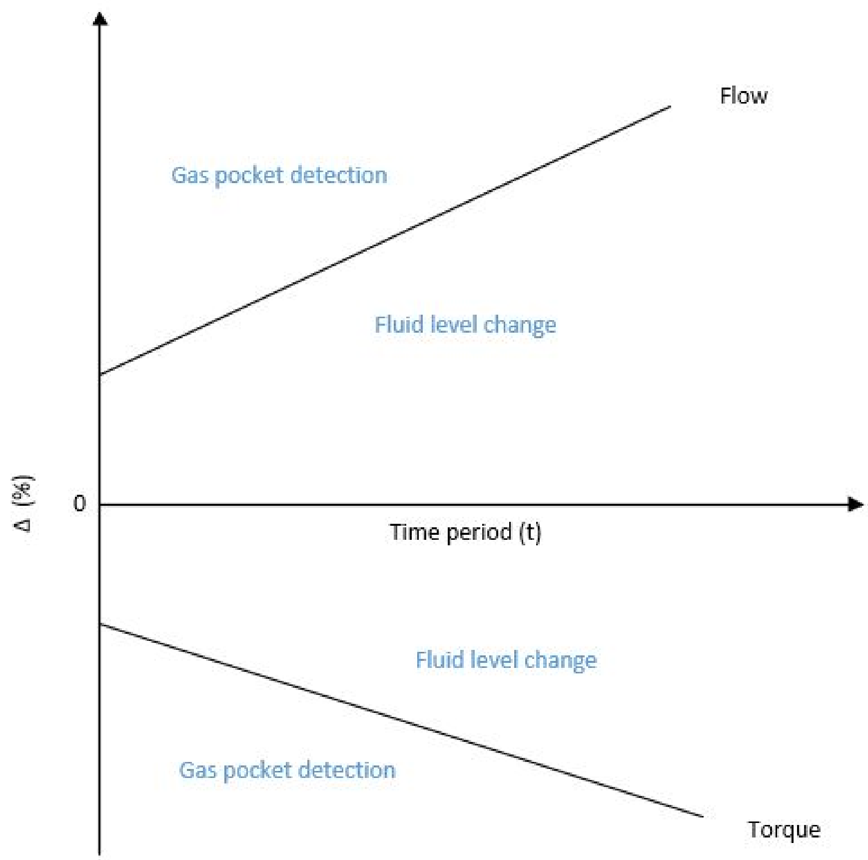


Figure 5.2: *Principle to identify different downhole situations.*

As at the moment, the function should have a limit for low torque beyond a gas pocket limit. An intense torque drop usually indicates broken equipment, and it is therefore recommendable to shut down the pump immediately.

5.4 Flow estimation and production rates

Flow can be determined without a separate flow sensor. However, this requires the wellhead pressure (tubing head pressure) value and valve size. The estimation is pretty accurate if pressure is constantly measured. Similarly, the flow value at intake can be estimated with knowledge of the casing pressure and intake size. By comparing these values, possible leaks can be detected as well. Flow can be estimated, for example, with Gilbert's correlation presented in Equation 5.8 [15]

$$v = \frac{P \times d^{1.89}}{435 \times (GOR)^{0.546}} \tag{5.8}$$

where P is pressure, d is valve diameter (same as the tubing diameter for example) and GOR is gas/liquid ratio. It should be noted that constant value "435" used in the equation is applicable only if other values are imperial units. To estimate flow, new parameters for gas/liquid ratio and valves' diameters are needed in the control program.

Production rates can be derived directly from the flow rate. Parameters of gas and water ratios are therefore needed to determine the exact amounts. The current rate, inferred and already achieved production are calculated simply by multiplying flow by water cut and time constant. The gas ratio is already taken into account in the flow equation. To keep track of gas amounts, flow rate is multiplied by gas/liquid ratio. The given water and gas ratios are also used in the fluid level estimation since they affect the hydrostatic pressures.

5.5 Low speed detection

The purpose of the low speed detection function is to protect the pump from a stall condition at start up. The current underload function reacts to situations where torque is lower than the set limit at a certain speed, but time is not included in the monitoring. The new principle discussed in Section 5.3 detects abnormal situations during normal operation, but it is not very useful at start-up where conditions change constantly. Also, acceleration ramps might be hours long and that is why it would be good to separate start-up monitoring from normal monitoring.

To detect a stall condition already in the start-up stage, the actual speed of the motor is compared against the calculated speed based on the acceleration ramp. If a certain speed is not achieved after a delay, the program warns about a stall condition. Figure

5.3 presents this principle. The limit and delay should be configurable so that the limit is a percentage of the calculated speed of the acceleration ramp and the delay a percentage of total ramp time. A static limit is not as effective since different shapes of ramps are available.

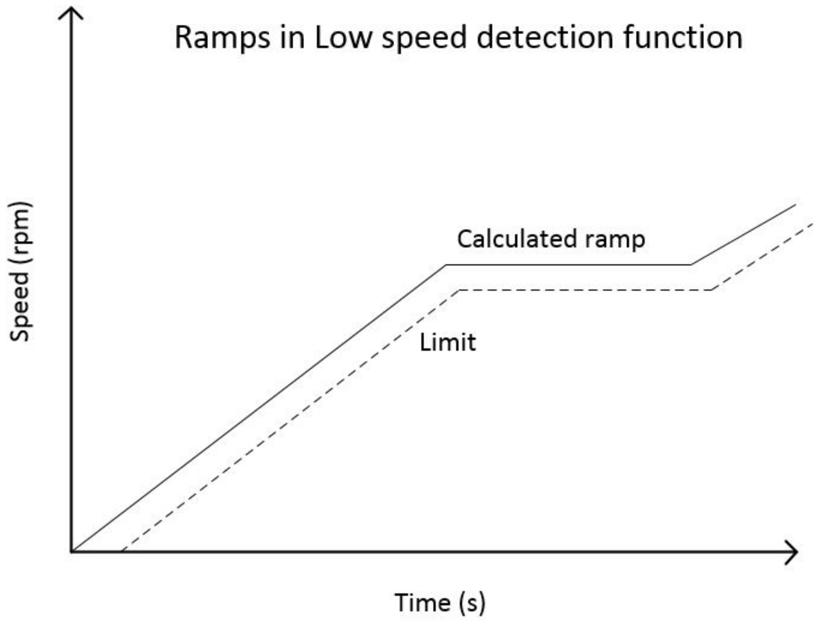


Figure 5.3: *Low speed detection function principle.*

5.6 Pump cleaning functions

Demand for automated cleaning functions for pumps occurred several times during inquiries. In practice, the current jogging function requires a manual start when it is used, and a better solution is requested. The design of the rocking start function, which runs the pump rapidly back and forth at start-up, has already started during writing this thesis. It can be programmed to do the same operation at other times as well. The activation of this function can be based on torque or time, for example, once every day. When torque rises above the set limit, the cleaning function is activated to get excess particles out of the pump so that normal operation can be continued.

With the direct torque control method, this functionality is pretty straightforward to design. DTC enables the use of high starting torques, which are required for an effective rocking start. With scalar control this is more challenging to do, since torque cannot be used as a reference value. To safely achieve high torque with scalar control, IR-compensation is needed. It compensates load changes by sensing the increased motor current and increasing the voltage feed to the motor based on that. The effect of the voltage increase to frequency should not be bigger than the slip frequency or the transformer might saturate [28]. The current control program can already estimate slip frequency. This way a torque boost can be done in a controlled way.

5.7 Motor control and supervision improvements

Demand for overall better motor control and supervision occurred with ESP applications. With progressing cavity pumps, step-up transformers and sine-filters are not usually part of the system, so the DTC method can be used as the motor control method. ESP applications usually run with scalar control, and also the conditions that ESP applications face are usually harsh and equipment is at its sustainability limits. That is why preventative maintenance functions would be valuable. Especially, a failure of a downhole motor is expensive maintenance work, and even short notices before a possible breakdown would be beneficial.

To make DTC work with a sine filter and transformer, it would require very complex new modelling. At the moment in the scalar control method, flux can be optimized and estimates of torque, speed and slip are already available. However, the accuracies of these estimations are inferior compared to equivalent DTC accuracies. IR-compensation will improve torque performance of scalar control, but flux optimization is not field oriented, and therefore torque cannot be effectively optimized. If a larger development process regarding ESP with DTC is not started, the current scalar control method could be at least marketed better since it offers more features compared to the plain scalar control method. Some other already existing features could be also emphasized. Several competitors mention a gas lock prevention function, which is simply based on keeping intake pressure stable by varying motor speed. This can be done by using a pressure signal as a reference value for the speed controller and by adjusting the set point to a value which gives stable flow. Some automatic searching routine for this could be considered as well.

The control program has a motor thermal protection function, which can estimate temperature and shut down the motor in case the temperature rises too much. In scalar mode, it is based on the drive output current, and it would be more accurate if an estimation of the motor current would be used as is done in DTC mode. Alternatively, operation time spent over nominal current and recommendable temperatures could be monitored and used to approximate remaining lifetime. Also, a user-definable U/f-curve to scalar mode would be quite easy to add to the control program.

5.8 Summary of implementations

Benefits and design requirements of presented improvements are collected to Table 5.1. Based on this, it is easier to evaluate the need for them and to plan the upcoming design process.

Table 5.1: *Benefits and requirements of suggested improvements.*

Functionality	**Benefit**	**Design requirements**
Fluid level estimation	No downhole sensors are needed to estimate fluid level in the well. This reduces costs and eliminates the possibility of maintenance due to broken downhole sensors.	User-defined parameters for fluid and gas densities, oil viscosity and tubing length. Displacement factor and friction torque are also required and can be added to pump data parameter group. Function itself should not be very complicated to add into the control program, but it needs a couple months of testing to ensure effectiveness.
Optimal fluid level finder	An automatic algorithm calculates the level where production is at the highest faster compared to a trial-error searching approach.	Production rate, fluid level (estimate or actual value) and reservoir pressure are firstly needed. Fluid densities and depth of perforations in casing are also required as user-defined parameters.
Gas pocket detection	Detection and reacting to gas pockets by automatically reducing speed prevents gas locks and system downtime. Naturally, this improves overall efficiency of the system.	If underload functionalities are modified as presented in section 5.3, pretty compehensive developing and testing is required.

Flow estimations and production rates	Flow estimations without flow sensors reduces overall costs of a pump system. Production estimates derived from flow values give a better overview of the system and help the planning of production. Leaks can also be detected.	Valve diameters (intake and discharge) are user-defined parameters as well as gas and water cuts in oil. Pressure values at measuring points are also needed.
Low speed detection	Detects abnormal situations like stalling or broken equipment during start-up and prevents additional damages.	Limit and delay are user-defined and therefore require their own parameters.
Anti-jam cleaning function	Cleans pump from excess particles at start-up, as well as other times, improving the pump's productivity.	High torque demand requires IR-compensation in the scalar control mode. New parameters for scheduled operations are also needed.
Motor control and supervision improvements	Improves control accuracy and helps to evaluate upcoming failures.	Modelling a sine wave filter and transformer, so that DTC could be used, would require a large development process. A motor's thermal supervision could be enhanced by using motor current estimates and monitoring more accurately the operation time over nominal values.

6. CONCLUSIONS

This chapter draws together the findings regarding ABB's PCP/ESP application control development presented in the thesis. Development requests and suggestions are prioritized based on demand, value for customers and effectiveness against competitors' offerings. Prioritization is useful since all enhancements cannot be done at once. This chapter also presents ABB's position in the market after different improvements are done. With the said information, it is easier to plan selling arguments and strategy.

6.1 Priorization

To respond to customer requirements and competitor offerings in the most effective way, the control program's features should be designed towards a more sensorless direction. A good starting point for that would be a fluid level estimation function. This estimation combined with an optimal fluid level finder would be even more valuable. One important measure is that downhole instrumentation is reduced. Generally, every functionality achieving this is valuable. Flow estimations would therefore be beneficial as well. Based on flow values, it is possible to develop more comprehensive production monitoring functions. These are often requested and already offered by main competitors. The same situation is with the sand cleaning functionality, which could be designed with the ability of scheduled operation. Based on the requests, and to develop a more competitive product, these four main topics are top priorities.

The current underload function can already react to gas pockets and stall conditions at some level if the modifiable curve is correctly set. That is why a new gas pocket detection functionality should not be prioritized high to be developed. Nevertheless, it is an important feature and should be considered at some stage. When speaking of torque and load monitoring functionalities, it would be better to focus on start-up at first. Low speed detection and programmable acceleration ramps would respond to customer requirements and competitor offering with far less effort. Thus, these functionalities would be prioritized to a medium level.

Table 6.1: *Priority order of the new functionalities.*

Functionality	**Priority**
Fluid level estimation (combined with optimal fluid level finder)	Top priority
Rocking start - cleaning function	High priority
Flow estimations	High priority
Production monitoring improvements	High priority
Low speed detection	Medium priority
Programmable acceleration ramps	Medium priority
Gas pocket detection	Medium priority
Motor lifespan estimate	Low priority
Programmable U/f-curve	Low priority
Parameter sets for different motors	Low priority

A direct torque control method working with a sine wave filter would be a major improvement and would raise ABB to the top spot. However, that would require a long development process on the motor control side, and it is already decided that only minor enhancements will be done. These improvements are not directly related to PCP/ESP application program, so they are to be considered on some other occasion. Nonetheless, some application specific improvements related to the motor should be considered. Programmable U/f-curve and parameter sets for different motors used with oil applications would be a good addition to the program. Preventative maintenance notifications related to motor conditions would also be a good selling argument. However, these are prioritized at the lowest level. Table 6.1 shows the suggested priority order for different functionalities.

6.2 Product positioning

This section presents the outcome of function improvements from the positioning point of view, where the improved ABB product is compared against the main competitors. Both the application specific functionalities and general performance are taken into account. Comprehensive positioning, which includes all elements and features of offered solutions, is challenging to do. It is difficult to determine whether it is more important to have, for example, a dedicated control program or good application programming possibilities. In this case, positioning is done by comparing ready-made solutions for oil pumping and the standard features of the converter. Thus, possible options and extension are included in the standard feature category.

6.2.1 Progressing cavity pumping

Figure 6.1 shows a market positioning for PCP control products if all requested improvements presented in Table 6.1 would be done. With these enhancements, ACS880 with PCP/ESP the application control program would be the most advanced ready-made control solution for PCP systems. Good overall performance and standard features of the ACS880 would make it highly competitive against any competitor in its category (low voltage industrial drives).

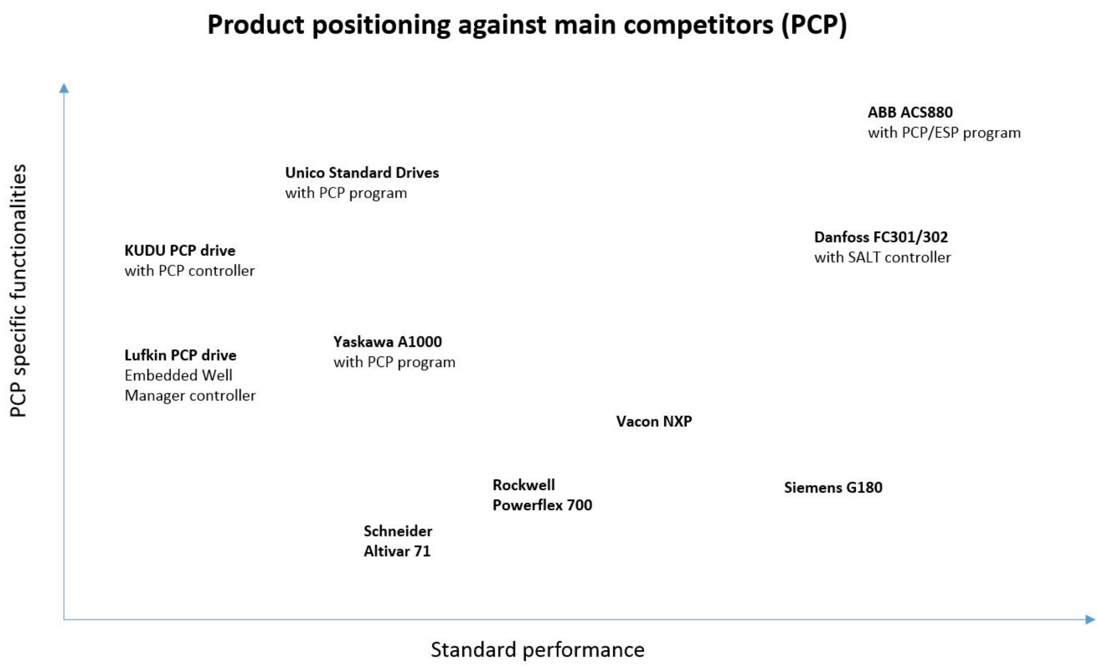


Figure 6.1: *PCP product positioning against competitors after requested improvements.*

All functions are not probably going to be added to the program, so Figure 6.2 shows the outcome of product positioning after high priority functions are added to the program. Even in this case, the application program is very competitive and only Unico has more functionalities. The standard performance of ABB's ACS880 is far better compared to Unico, thus altogether, ABB's solution is strong.

6.2.2 Electric submersible pumping

Frequency converters used in ESP applications fall under two categories: low and medium voltage. Therefore, the positioning chart does not give a complete picture of the situation. Medium voltage converters generally have better standard features

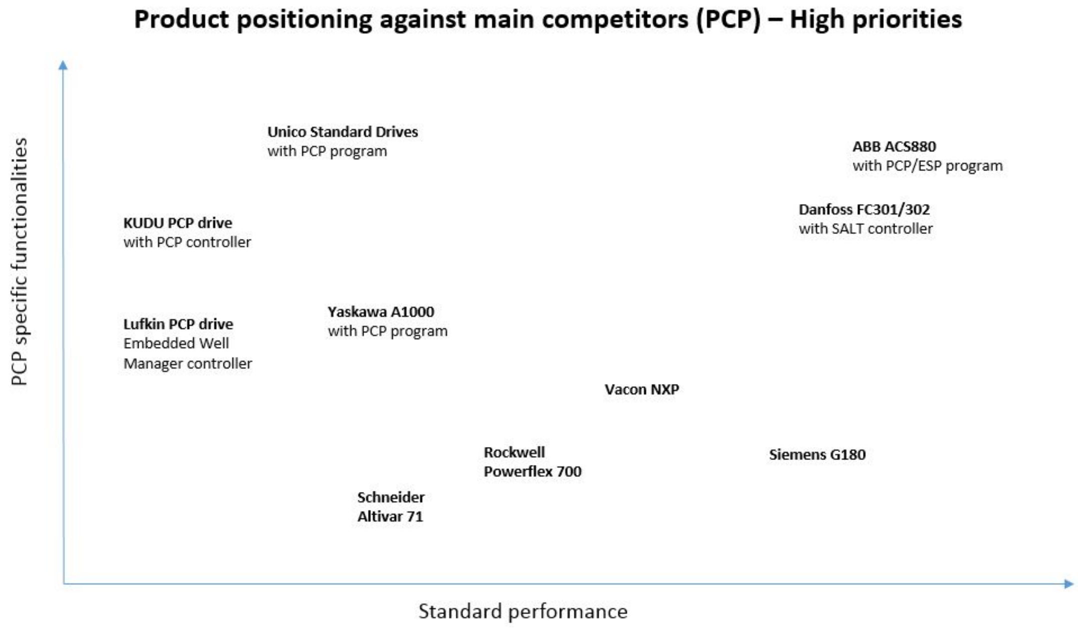


Figure 6.2: *PCP product positioning against competitors after high priority improvements.*

and performance, but they are also significantly more expensive compared to low voltage converters. Similarly to the PCP positioning, new function improvements would raise the ACS880 as the most advanced ready-made ESP control solution in the low voltage category. It would still be behind medium voltage competitors when comparing performance features. However, ABB would still have better application specific properties as Figure 6.3 shows.

Similarly to the PCP section, the positioning after high priority functions shows a more realistic and comparable situation. Figure 6.4 shows that ABB's program is still strong against other low voltage solutions.

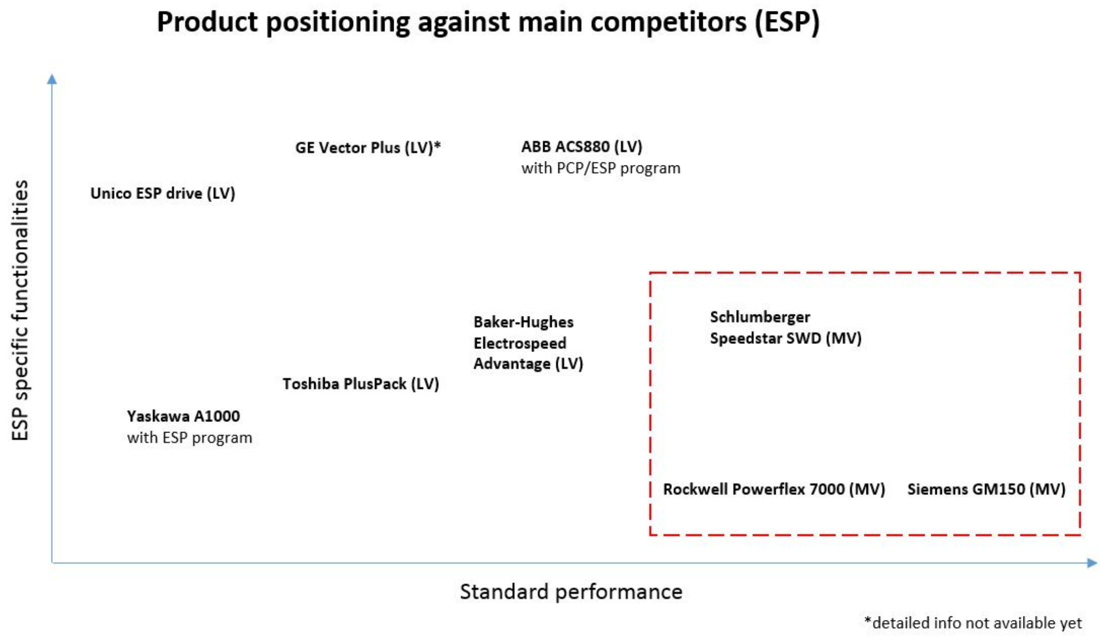


Figure 6.3: *ESP product positioning against competitors after requested improvements*

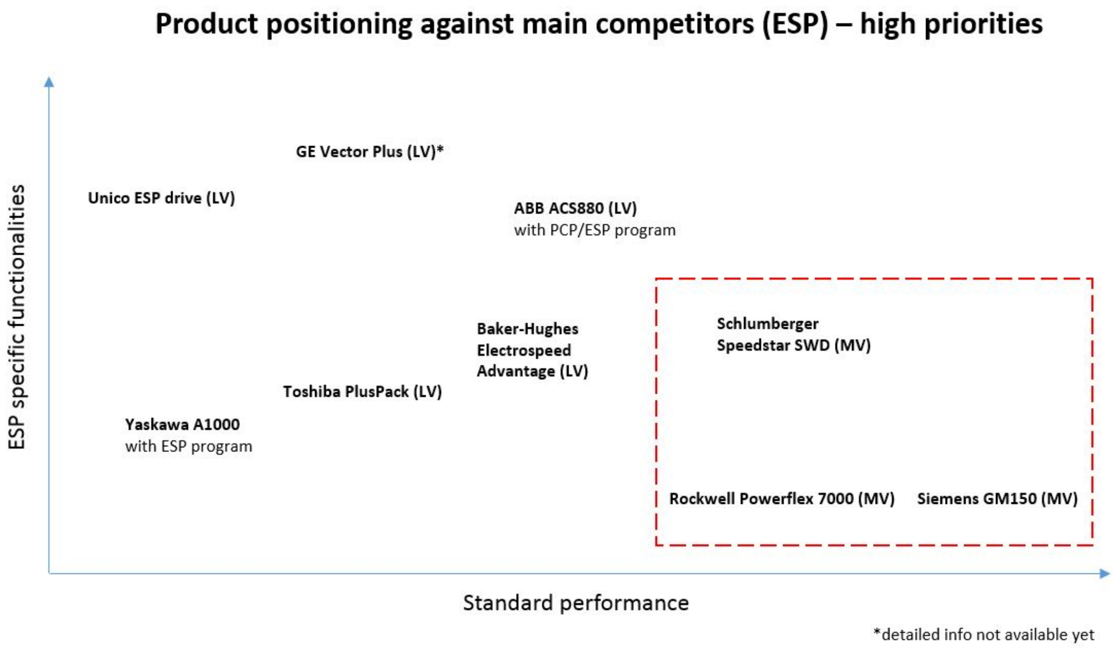


Figure 6.4: *ESP product positioning against competitors after high priority improvements*

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A. APPENDIX: PCP AND ESP FUNCTIONALITY COMPARISON TABLES

Table A.1: *PCP functionality comparison*

	ABB PCP control program	**Unico PCP control program**	**Lufkin PCP controller**
Backspin control	Yes	Inludes power survival mode during power outage.	No
Motor control	Vector (DTC) or scalar	Vector (FOC) or scalar	Vector (FOC) or scalar
Motor torque protection	High and low torque limits with speed reference change. User-definable underload curve (speed-torque).	Static high and minimum torque limits.	High torque limit with automatic speed reduction. Torque limiter function warns before high limit.
Pump pressure protection	With sensors	Casing, tubing, intake and discharge (differential) pressures. Estimations used if sensors aren't used.	Discharge pressure with sensor.
Pump thermal protection	With PT-100 or Klixon sensors	Fluid, tubing and casing temperatures with sensors	Fluid temperature at discharge with sensor.
Fluid level control	Yes. Level measurement with fluid level or pressure sensor.	Either well or discharge tank mode. Sensorless fluid level estimation.	No
Fluid level sleep function	Yes	Yes	No
Built-in production monitoring and control	No	Oil, gas, water and leakage amounts can be monitored sensorless.	Production control mode for keeping production within set limits.
Brake confirmation	Yes	No	No
Acceleration ramps	Linear, s-shape and two-stage ramps up to 5.5 h	Linear ramp up to 2 h	Linear ramp up to one day
Cleaning and maintenance functions	Jogging function with manual start	Backflush function (reverse purge), based on either time or torque.	Sand blowout function (reverse purge) based on torque.
Calendar and timer based operations	No	Yes	Yes
Auto restart	Yes	Yes	Yes

Table A.2: *PCP functionality comparison (continues)*

	Yaskawa PCP control program	**Kudu PCP control program**	**Danfoss SALT controller**	**Vacon PCP control program**
Backspin control	Yes	Includes power survival mode during power outage.	No	Includes power survival mode during power outage.
Motor control	Vector (FOC) or scalar	Vector (FOC) or scalar	Vector (FOC) or scalar	Vector (FOC) or scalar
Motor torque protection	High torque limit. Undertorque detection with frequency boost. Low speeds also monitored.	High torque limit with automatic speed reduction. Torque limiter function warns before high limit.	High torque limit. Underload function (gas pocket detection) with automatic speed reduction.	High and low torque limits with automatic speed reduction.
Pump pressure protection	High and low pressure detection with sensors.	Intake, discharge, casing and line pressure limits with automatic speed reduction.	With sensors	Indirect downhole pressure estimations
Pump thermal protection	With sensors	Discharge and line temperature limits with automatic speed reduction.	With sensors	Indirect downhole temperature estimation
Fluid level control	No	No	Yes, adjacent wells also taken in account.	No
Fluid level sleep function	No	No	N/A	No
Built-in production monitoring and control	No	Production amounts, cavity low fillage and wear monitored. Production optimization based on flow.	Production monitored with 30 day log. Production optimization based on flow or other input.	Production optimized based on measured values (flow, temperature, pressure).
Brake confirmation	No	No	No	No
Acceleration ramps	Linear ramp up to 1.5 h	N/A	Linear ramp up to 1 h	Linear ramp up to 1 h
Cleaning and maintenance functions	Custom run sequence with programmable start	Rocking start and sand-blowout function	Sand-purge (also gas handling) function	No
Calendar and timer based operations	No	N/A	No	No
Auto restart	Yes	Yes	Yes	Yes

Table A.3: *ESP functionality comparison*

	ABB ESP control program	**Toshiba LV Plus Pack**	**Baker-Hughes Electrospeed LV Advantage**
Motor control	Scalar / enhanced speed control (flux and slip estimations)	Scalar control with automatic or defined boost at start	Scalar control with boost start.
Backspin control/detection	Yes	Yes	
Power ride through	No	Yes	Yes
Motor torque protection	High and low torque limits with speed reference change. User-definable underload curve (speed-torque).	High torque limit and "abnormal" speed detection.	High torque limit
Pump pressure protection	With sensors	With sensor. Pressure based speed control is possible.	With sensors
Pump thermal protection	PT-100 or Klixon sensors	With sensors	With sensors
Fluid level control	Yes	Yes	Yes
Fluid level sleep function	Yes	Yes	N/A
Buit-in production monitoring and control	No	No. Flow based speed control function. Leak detection function.	No. Production optimization based on intake pressure.
Acceleration ramps	Linear, s-shape and two-stage ramps up to 5.5 h	Linear, s-curve and automatic ramp up to 1.5 h	N/A
Auto restart	Yes	Yes	Yes
Cable compensation	Yes	No	Yes
Cleaning and maintenance functions	Jogging function with manual start	Rocking start and jogging sequence	Boosted start.

Table A.4: *ESP functionality comparison (continues)*

	Unico LV ESP drive	**Yaskawa ESP control program**	**Schlumberger Speedstar SWD MV drive**
Motor control	Scalar control. Supercharging functionality automatically operates above base speed during reduced pump loading.	Scalar control	Scalar control. Intergrated sine filter. Speed control based on motor loading.
Backspin control/detection	Yes	Yes	Yes
Power ride through	No	No	Yes
Motor torque protection	High and low torque limit. Low speed detection.	High and low torque limit. Low speed detection at start-up.	High torque limit with automatic speed reduction
Pump pressure protection	Pressure values are estimated if sensors aren't used	High and low pressure detection with sensors	With sensors
Pump thermal protection	Fluid, tubing and casing temperature monitoring with sensors	With sensors	With sensors
Fluid level control	Yes. Optimal fluid level finder function. Can be done sensorless.	No	No dedicated function
Fluid level sleep function	Yes	No	No
Buit-in production monitoring and control	Flow and production amounts can be monitored sensorless. Production optimization based on flow or intake pressure.	No	No monitoring. Production optimization based on intake pressure.
Acceleration ramps	Adjustable ramps	Speed step function during start-up	Maintains constant pressure or load using minimun and target speeds during acceleration. Rates from 0,01 Hz/10000 s to 1 Hz/1 s.
Auto restart	Yes	Yes	Yes
Cable compensation	Yes	No	No
Cleaning and maintenance functions	No	Custom run sequence with programmable start	Rocking start